6031 (02-14-08)

ANNUAL REPORT

OF

Name: NORTHERN STATES POWER COMPANY (WISCONSIN)

Principal Office: 1414 W. HAMILTON AVENUE
P.O. BOX 8
EAU CLAIRE, WI 54702-0008

For the Year Ended: DECEMBER 31, 2009

WATER, ELECTRIC, OR JOINT UTILITY
TO
PUBLIC SERVICE COMMISSION OF WISCONSIN

P.O. Box 7854
Madison, WI 53707-7854
(608) 266-3766

This form is required under Wis. Stat. § 196.07. Failure to file the form by the statutory filing date can result in the imposition of a penalty under Wis. Stat. § 196.66. The penalty which can be imposed by this section of the statutes is a forfeiture of not less than $25 nor more than $5,000 for each violation. Each day subsequent to the filing date constitutes a separate and distinct violation. The filed form is available to the public and personally identifiable information may be used for purposes other than those related to public utility regulation.

Version: 3.09

GENERAL RULES FOR REPORTING

1. Prepare the report in conformity with the Uniform System of Accounts prescribed by the Public Service Commission of Wisconsin.

2. Numeric items shall contain digits (0-9). A minus sign "-" shall be entered in the software program to indicate negative values. Parentheses shall not be used for numeric items. The program will convert the minus sign to parentheses for hard copy annual report purposes. Negative values may not be allowed for certain entries in the annual report due to restrictions contained in the software program.

3. The annual report should be complete in itself in all particulars. Reference to reports of former years should not be made to take the place of required entries except as otherwise specifically authorized.

4. Whenever schedules call for data from the previous year, the data reported must be based upon those shown by the annual report of the previous year or an appropriate explanation given why different data is being reported for the current year. Where available, use an adjustment column.

5. All dollar amounts will be reported in whole dollars.

6. Wherever information is required to be shown as text, the information shall be shown in the space provided using other than account titles. In each case, the information shall be properly identified. Footnote capability is included in the annual report software program and shall be utilized where necessary to further explain particulars of a schedule.

7. The deadline for filing the Annual Report is April 1, 2010.

SIGNATURE PAGE

I TERESA S. MADDEN of
(Person responsible for accounts)

NORTHERN STATES POWER COMPANY (WISCONSIN), certify that I
(Utility Name)

am the person responsible for accounts; that I have examined the following report and, to the best of my knowledge, information and belief, it is a correct statement of the business and affairs of said utility for the period covered by the report in respect to each and every matter set forth therein.

(Signature of person responsible for accounts)

04/30/2010
(Date)

VICE PRESIDENT & CONTROLLER
(Title)

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IDENTIFICATION AND OWNERSHIP

Exact Utility Name: NORTHERN STATES POWER COMPANY (WISCONSIN)
Utility Address: 1414 W. HAMILTON AVENUE
P.O. BOX 8
EAU CLAIRE, WI 54702-0008
When was utility organized? 11/21/1901
Previous name:
Date of change:
Utility Web Site: www.xcelenergy.com

Telephone numbers for potential customers to contact company:
Business Customers: (800) 481 - 4700
Residential Customers: (800) 895 - 4999

Primary Utility Contact (located at utility address):

Name: TERESA S. MADDEN
Title: VICE PRESIDENT AND CONTROLLER
Office Address: NORTHERN STATES POWER COMPANY (WISCONSIN)
414 NICOLLET MALL, SUITE 400
MINNEAPOLIS, MN 55401

Telephone: (612) 215 - 4560
Fax Number: ( ) -
E-mail Address: teresa.s.madden@xcelenergy.com

Contact person for information contained in this annual report:

☐ **Same as Primary Address**
Name: KAREN L. EVERSON
Title: DIRECTOR, UTILITY ACCOUNTING - NSPM & NSPW
Office Address: NORTHERN STATES POWER COMPANY (WISCONSIN)
1414 W. HAMILTON AVENUE
P.O. BOX 8
EAU CLAIRE, WI 54702-0008
Telephone: (715) 737 - 2417
Fax Number: (715) 737 - 5494
E-mail Address: karen.l.everson@xcelenergy.com

Contact person for Regulatory Inquiries and Complaints:

☐ **Same as Primary Address**
Name: KARL J. HOESLY
Title: MANAGER, REGULATORY AFFAIRS
Office Address: NORTHERN STATES POWER COMPANY (WISCONSIN)
1414 W. HAMILTON AVENUE
P.O. BOX 8
EAU CLAIRE, WI 54702-0008
Telephone: (715) 737 - 4012
Fax Number:
E-mail Address: karl.j.hoesly@xcelenergy.com

CONTROL OVER RESPONDENT

If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

100% of the voting stock of Northern States Power Company (Wisconsin) is held by Xcel Energy Inc., a publicly owned company.
Northern States Power Company (Wisconsin) is a first tier subsidiary of Xcel Energy Inc.

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.
4. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

DEFINITIONS

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)		
Chippewa and Flambeau Improvement Company	Operate hydro reservoirs	78.00%	*	1
Clearwater Investments, Inc.	Affordable housing	100.00%		2
NSP Lands, Inc.	Real estate holdings	100.00%		3

CORPORATIONS CONTROLLED BY RESPONDENT

Corporations Controlled by Respondent (Page vi)

General footnotes

As of 12/31/2009, Northern States Power Company (Wisconsin) owned 78.28% of the outstanding shares of stock of Chippewa and Flambeau Improvement Company.

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Teresa S. Madden
Vice President and Controller
414 Nicollet Mall, Suite 400
Minneapolis, MN 55401

1414 W. Hamilton Ave, P.O. Box 8
Eau Claire, WI 54702-0008

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

The respondent was incorporated under the laws of the State of Wisconsin on November 21, 1901.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) the name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

During the year 2009, the respondent furnished electric utility and gas utility service in the states of Wisconsin and Michigan.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

○ Yes If yes, enter the date when such independent accountant was initially engaged:

● No

OFFICERS' SALARIES

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Title (a)	Name of Officer (b)	Salary for Year (c)		
Chairman of the Board	Richard C. Kelly	66,740	*	1
President and Chief Executive Officer	Michael L. Swenson	254,102		2

OFFICERS' SALARIES

Officers' Salaries (Page viii)

General footnotes

Salaries represent NSP-Wisconsin's allocation of officers' salaries greater than $50,000 for the period of time that was served as an officer for NSP-Wisconsin.

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Name/Title and Principal Business Address (a)	Length Of Term (Years) (b)	Term Expires (c)	Meetings Attended (d)		
MICHAEL L. SWENSON/PRESIDENT AND CHIEF EXECUTIVE OFFICER 1414 W. HAMILTON AVE. EAU CLAIRE, WI 54701	7	09/22/2010	4		1
RICHARD C. KELLY/CHAIRMAN 414 NICOLLET MALL, SUITE 500 MINNEAPOLIS, MN 55401	9	09/22/2010	4		2
BENJAMIN G.S. FOWKE III/VICE PRESIDENT 414 NICOLLET MALL, SUITE 500 MINNEAPOLIS, MN 55401	5	09/22/2010	4		3
DAVID M. SPARBY/VICE PRESIDENT AND CHIEF FINANCIAL OFFICER 414 NICOLLET MALL, SUITE 500 MINNEAPOLIS, MN 55401	0	09/22/2010	2	*	4

DIRECTORS

Directors (Page ix)

General footnotes

NSP-Wisconsin's Executive Committee was rescinded by Board of Director resolution dated 12/15/2000.

David M. Sparby was elected as Director, Vice President and Chief Financial Officer, effective August 26, 2009.

COMMON STOCKHOLDERS

From the stockholder list nearest the end of the year report the greatest of: 1) the ten largest shareholders of voting securities or 2) all shareholders owning 5% or more of voting securities. List names, addresses and shareholdings. If any stock is held by a nominee, give known particulars as to the beneficial owner (see Wis. Stat. § 196.795(1)(c), for definition of beneficial owner).

Date of stockholders' list nearest end of year: 12/31/2009

	Common	Preferred	Total
Number of stockholders on above date:	1		1
Number of shareholders in Wisconsin:			0
Percent of outstanding stock owned by Wisconsin Stockholders:			

Stockholders:

Name: XCEL ENERGY INC. **1**
Address: 414 NICOLLET MALL
MINNEAPOLIS, MN 55401

Number of Shares Held: 933,000
Beneficial Owner:

INCOME STATEMENT

Particulars (a)	This Year (b)	Last Year (c)	
UTILITY OPERATING INCOME			
Operating Revenues (400)	694,384,366	739,093,130	1
Operating Expenses:			
Operating Expenses (401)	491,944,643	539,438,435	2
Maintenance Expenses (402)	22,801,643	23,859,366	3
Depreciation Expense (403)	55,765,187	51,868,443	4
Depreciation Expense for Asset Retirement Costs (403.1)	0	0	5
Amort. & Depl. Of Utility Plant (404-405)	4,754,683	5,174,894	6
Amort. Of Utility Plant Acq. Adj. (406)	0	0	7
Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)	0	0	8
Amort. Of Conversion Expenses (407.2)	0	0	9
Regulatory Debits (407.3)	0	0	10
Less: Regulatory Credits (407.4)	168,658	168,657	11
Taxes Other Than Income Taxes (408.1)	23,067,299	20,776,115	12
Income Taxes - Federal (409.1)	15,279,387	20,616,481	13
Income Taxes - Other (409.1)	5,414,071	6,516,090	14
Provision for Deferred Income Taxes (410.1)	79,020,121	32,438,675	15
Less: Provision for Deferred Income Taxes-Cr. (411.1)	70,359,182	30,076,937	16
Investment Tax Credit Adj. - Net (411.4)	(633,856)	(629,324)	17
Less: Gains from Disp. Of Utility Plant (411.6)	0	0	18
Losses from Disp. Of Utility Plant (411.7)	0	0	19
Less: Gains from Disposition of Allowances (411.8)	161,322	161,322	20
Losses from Disposition of Allowances (411.9)	0	0	21
Accretion Expense (411.10)	0	0	22
Total Utility Operating Expenses:	**626,724,016**	**669,652,259**	
Net Operating Income	**67,660,350**	**69,440,871**	
OTHER INCOME			
Revenues From Merchandising, Jobbing and Contract Work (415)	0	648	23
Less: Costs and Exp. Of Merchandising, Job. & Contract Work (416)	0	0	24
Revenues From Nonutility Operations (417)	136,761	168,952	25
Less: Expenses of Nonutility Operations (417.1)	79,186	149,888	26
Nonoperating Rental Income (418)	6,998	59,304	27
Equity in Earnings of Subsidiary Companies (418.1)	(29,642)	(20,813)	28
Interest and Dividend Income (419)	877,648	(71,904)	29
Allowance for Other Funds Used During Construction (419.1)	1,421,031	619,052	30
Miscellaneous Nonoperating Income (421)	301,168	384,305	31
Gain on Disposition of Property (421.1)	0	23,458	32
Total Other Income	**2,634,778**	**1,013,114**	
OTHER INCOME DEDUCTIONS			
Loss on Disposition of Property (421.2)	0	0	33
Miscellaneous Amortization (425)	0		34
Donations (426.1)	876,016	902,185	35
Life Insurance (426.2)	(207,754)	(155,761)	* 36
Penalties (426.3)	1,734	(4,714)	37
Exp. For Certain Civic, Political & Related Activities (426.4)	451,740	492,410	38

INCOME STATEMENT

Particulars (a)	This Year (b)	Last Year (c)	
OTHER INCOME DEDUCTIONS			
Other Deductions (426.5)	937,437	226,518	**39**
Total Other Income Deductions	**2,059,173**	**1,460,638**	
TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS			
Taxes Other Than Income Taxes (408.2)	127,199	128,643	**40**
Income Taxes-Federal (409.2)	1,428,885	(373,405)	**41**
Income Taxes-Other (409.2)	(4,200,419)	(171,991)	**42**
Provision for Deferred Inc. Taxes (410.2)	442,417	2,497,413	**43**
Less: Provision for Deferred Inc. Taxes - Cr. (411.2)	747,959	3,022,986	**44**
Investment Tax Credit Adj.-Net (411.5)			**45**
Less: Investment Tax Credits (420)			**46**
Total Taxes Applicable to Other Income and Deductions	**(2,949,877)**	**(942,326)**	
Net Other Income and Deductions	**3,525,482**	**494,802**	
INTEREST CHARGES			
Interest on Long-Term Debt (427)	22,717,264	22,479,822	**47**
Amort. of Debt. Disc. And Expense (428)	282,455	277,409	**48**
Amortization of Loss on Reaquired Debt (428.1)	769,800	964,745	**49**
Less: Amort. of Premium on Debt-Credit (429)	0	0	**50**
Less: Amortization of Gain on Reaquired Debt-Credit (429.1)	0	0	**51**
Interest on Debt to Assoc. Companies (430)	59,194	1,039,543	**52**
Other Interest Expense (431)	811,980	706,028	**53**
Less: Allowance for Borrowed Funds Used During Construction-Cr. (432)	817,781	1,052,559	**54**
Total Interest Charges	**23,822,912**	**24,414,988**	
Income Before Extraordinary Items	**47,362,920**	**45,520,685**	
EXTRAORDINARY ITEMS			
Extraordinary Income (434)	0	0	**55**
Less: Extraordinary Deductions (435)	0	0	**56**
Net Extraordinary Items:	**0**	**0**	
Income Taxes-Federal and Other (409.3)			**57**
Extraordinary Items After Taxes	**0**	**0**	
Net Income	**47,362,920**	**45,520,685**	

INCOME STATEMENT

Income Statement (Page F-01)

General footnotes

Life Insurance (426.2) - Income on Company Owned Life Insurance.

INCOME STATEMENT - REVENUES & EXPENSES BY UTILITY TYPE

Particulars (a)	TOTAL This Year (b)	TOTAL Last Year (c)		
Operating Revenues (400)	694,384,366	739,093,130		1
Operating Expenses:				
Operating Expenses (401)	491,944,643	539,438,435		2
Maintenance Expenses (402)	22,801,643	23,859,366		3
Depreciation Expense (403)	55,765,187	51,868,443	*	4
Depreciation Expense for Asset Retirement Costs (403.1)	0	0		5
Amort. & Depl. Of Utility Plant (404-405)	4,754,683	5,174,894		6
Amort. Of Utility Plant Acq. Adj. (406)	0	0		7
Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)	0	0		8
Amort. Of Conversion Expenses (407.2)	0	0		9
Regulatory Debits (407.3)	0	0		10
Less: Regulatory Credits (407.4)	168,658	168,657		11
Taxes Other Than Income Taxes (408.1)	23,067,299	20,776,115		12
Income Taxes - Federal (409.1)	15,279,387	20,616,481		13
Income Taxes - Other (409.1)	5,414,071	6,516,090		14
Provision for Deferred Income Taxes (410.1)	79,020,121	32,438,675		15
Less: Provision for Deferred Income Taxes-Cr. (411.1)	70,359,182	30,076,937		16
Investment Tax Credit Adj. - Net (411.4)	(633,856)	(629,324)		17
Less: Gains from Disp. Of Utility Plant (411.6)	0	0		18
Losses from Disp. Of Utility Plant (411.7)	0	0		19
Less: Gains from Disposition of Allowances (411.8)	161,322	161,322		20
Losses from Disposition of Allowances (411.9)	0	0		21
Accretion Expense (411.10)	0	0		22
Total Utility Operating Expenses:	626,724,016	669,652,259		
Net Operating Income:	67,660,350	69,440,871		

INCOME STATEMENT - REVENUES & EXPENSES BY UTILITY TYPE (cont.)

Electric Utility		Gas Utility		Other Utility			
This Year (d)	Last Year (e)	This Year (f)	Last Year (g)	This Year (h)	Last Year (000's) (i)		
561,690,877	557,877,259	132,478,834	180,998,742	214,655	217,129		1
381,116,742	382,961,651	110,827,901	156,476,784				2
21,120,838	22,294,853	1,680,805	1,564,513				3
48,309,935	45,003,810	7,416,795	6,826,176	38,457	38,457	*	4
							5
4,302,596	4,658,403	452,087	516,491				6
							7
							8
							9
							10
168,658	168,657						11
20,622,215	18,719,425	2,445,084	2,056,690				12
16,357,364	18,785,602	(1,105,634)	1,803,712	27,657	27,167		13
5,054,336	5,927,962	355,329	584,042	4,406	4,086		14
27,976,337	18,443,125	51,054,534	14,005,706	(10,750)	(10,156)		15
23,131,486	18,122,933	47,227,696	11,954,004				16
(604,765)	(600,261)	(26,835)	(27,130)	(2,256)	(1,933)		17
							18
							19
161,322	161,322						20
							21
							22
500,794,132	**497,741,658**	**125,872,370**	**171,852,980**	**57,514**	**57,621**		
60,896,745	**60,135,601**	**6,606,464**	**9,145,762**	**157,141**	**159,508**		

INCOME STATEMENT - REVENUES & EXPENSES BY UTILITY TYPE

Income Statement - Revenues & Expenses by Utility Type (Page F-02)

General footnotes

Other Utility Depreciation - Expense of Plant Leased to Others $38,457.

INCOME STATEMENT - REVENUES & EXPENSES BY UTILITY TYPE (cont.)

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BALANCE SHEET

Assets and Other Debits (a)	Balance End of Year (b)	Balance First of Year (c)	
UTILITY PLANT			
Utility Plant (101-106, 114)	1,773,819,474	1,708,026,968	**1**
Construction Work in Progress (107)	52,143,786	30,493,840	**2**
Total Utility Plant:	**1,825,963,260**	**1,738,520,808**	
Less: Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	875,018,980	831,403,260	**3**
Net Utility Plant:	**950,944,280**	**907,117,548**	
Nuclear Fuel in Process of Ref., Conv.,Enrich.,and Fab. (120.1)		0	**4**
Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	**5**
Nuclear Fuel Assemblies in Reactor (120.3)		0	**6**
Spent Nuclear Fuel (120.4)		0	**7**
Nuclear Fuel Under Capital Leases (120.6)		0	**8**
Less: Accum. Prov. For Amort. Of Nucl. Fuel Assemblies (120.5)		0	**9**
Net Nuclear Fuel:	**0**	**0**	
Net Utility Plant:	**950,944,280**	**907,117,548**	
Utility Plant Adjustments (116)		0	**10**
Gas Stored Underground - Noncurrent (117)		0	**11**
OTHER PROPERTY AND INVESTMENTS			
Nonutility Property (121)	2,822,923	2,811,145	**12**
Less: Accum. Prov. for Depr. And Amort. (122)	60,031	60,031	**13**
Investments in Associated Companies (123)	0	0	**14**
Investments in Subsidiary Companies (123.1)	3,220,740	3,288,436	**15**
Noncurrent Portion of Allowances		0	**16**
Other Investments (124)	4,058,135	3,854,080	**17**
Sinking Funds (125)	0	0	**18**
Depreciation Fund (126)	0	0	**19**
Amortization Fund - Federal (127)	0	0	**20**
Other Special Finds (128)	51,426	74,063	**21**
Special Funds (129)		0	**22**
Long-Term Portion of Derivative Assets (175)		0	**23**
Long-Term Portion of Derivative Assets - Hedges (176)	24,952	0	**24**
Total Other Property and Investments	**10,118,145**	**9,967,693**	
CURRENT AND ACCRUED ASSETS			
Cash (131)	0	0	**25**
Special Deposits (132-134)	393,548	393,040	**26**
Working Fund (135)	99,900	99,900	**27**
Temporary Cash Investments (136)	228,929	30,889,073	**28**
Notes Receivable (141)	0	0	**29**
Customer Accounts Receivable (142)	54,261,723	59,633,219	**30**
Other Accounts Receivable (143)	360,347	1,454,749	**31**
Less: Accum. Prov. For Uncollectible Acct.-Credit (144)	4,708,845	4,657,597	**32**
Notes Receivable from Associated Companies (145)	0	0	**33**
Accounts Receivable from Assoc. Companies (146)	20,449,276	599,821	**34**
Fuel Stock (151)	13,385,917	13,164,689	**35**
Fuel Stock Expenses Undistributed (152)	0	0	**36**
Residuals (Elec) and Extracted Products (153)	0	0	**37**
Plant Materials and Operating Supplies (154)	4,888,793	4,591,708	**38**
Merchandise (155)	531	531	**39**

BALANCE SHEET

Assets and Other Debits (a)	Balance End of Year (b)	Balance First of Year (c)	
CURRENT AND ACCRUED ASSETS			
Other Materials and Supplies (156)	0	0	**40**
Nuclear Materials Held for Sale (157)	0	0	**41**
Allowances (158.1 and 158.2)	2,990	0	**42**
Less: Noncurrent Portion of Allowances		0	**43**
Stores Expense Undistributed (163)	0	0	**44**
Gas Stored Underground - Current (164.1)	9,305,389	20,625,971	**45**
Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	860,080	1,093,974	**46**
Prepayments (165)	30,042,557	21,060,239	**47**
Advances for Gas (166-167)	0	0	**48**
Interest and Dividends Receivable (171)	78,728	0	**49**
Rents Receivable (172)	0	22,755	**50**
Accrued Utility Revenues (173)	44,907,438	42,639,385	**51**
Miscellaneous Current and Accrued Assets (174)	2,039,815	7,271,365	**52**
Derivative Instrument Assets (175)		0	**53**
(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	**54**
Derivative Instrument Assets - Hedges (176)	613,223	2,026	**55**
(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)	24,952	0	**56**
Total Current and Accrued Assets	**177,185,387**	**198,884,848**	
DEFERRED DEBITS			
Unamortized Debt Expenses (181)	2,902,543	3,367,821	**57**
Extraordinary Property Losses (182.1)		0	**58**
Unrecovered Plant and Regulatory Study Costs (182.2)		0	**59**
Other Regulatory Assets (182.3)	210,401,771	180,804,101	**60**
Prelim. Survey and Investigation Charges (Electric) (183)		0	**61**
Preliminary Natural Gas Survey and Investigation Charges (183.1)		0	**62**
Other Preliminary Survey and Investigation Charges (183.2)		0	**63**
Clearing Accounts (184)		0	**64**
Temporary Facilities (185)		0	**65**
Miscellaneous Deferred Debits (186)	1,855,499	2,805,073	**66**
Def. Losses from Disposition of Utility Plt. (187)		0	**67**
Research, Devel. And Demonstration Expend. (188)	0	0	**68**
Unamortized Loss on Reaquired Debt (189)	10,276,992	8,786,409	**69**
Accumulated Deferred Income Taxes (190)	99,405,429	76,127,628	**70**
Unrecovered Purchased Gas Costs (191)		0	**71**
Total Deferred Debits	**324,842,234**	**271,891,032**	
Total Assets and Other Debits	**1,463,090,046**	**1,387,861,121**	

BALANCE SHEET

Liabilities and Other Credits (a)	Balance End of Year (b)	Balance First of Year (c)	
PROPRIETARY CAPITAL			
Common Stock Issued (201)	93,300,000	93,300,000	**72**
Preferred Stock Issued (204)	0	0	**73**
Capital Stock Subscribed (202, 205)		0	**74**
Stock Liability for Conversion (203, 206)		0	**75**
Premium on Capital Stock (207)	33,337,651	33,337,651	**76**
Other Paid-In Capital (208-211)	113,166,938	91,370,059	**77**
Installments Received on Capital Stock (212)		0	**78**
(Less) Discount on Capital Stock (213)	0	0	**79**
(Less) Capital Stock Expense (214)	0	0	**80**
Retained Earnings (215, 215.1, 216)	251,463,375	238,230,830	**81**
Unappropriated Undistributed Subsidiary Earnings (216.1)	2,471,415	2,539,110	**82**
Less: Reaquired Capital Stock (217)		0	**83**
Accumulated Other Comprehensive Income (219)	(665,655)	(741,724)	**84**
Total Proprietary Capital	**493,073,724**	**458,035,926**	
LONG-TERM DEBT			
Bonds (221)	350,000,000	415,000,000	**85**
(Less) Reaquired Bonds (222)	0	0	**86**
Advances from Associated Companies (223)	0	0	**87**
Other Long-Term Debt (224)	19,292,590	19,326,375	**88**
Unamortized Premium on Long-Term Debt (225)	0	0	**89**
(Less) Unamortized Discount on Long-Term Debt-Debit (226)	1,965,283	2,233,921	**90**
Total Long-Term Debt	**367,327,307**	**432,092,454**	
OTHER NONCURRENT LIABILITIES			
Obligations Under Capital Leases - Noncurrent (227)		0	**91**
Accumulated Provision for Property Insurance (228.1)		0	**92**
Accumulated Provision for Injuries and Damages (228.2)		300,000	**93**
Accumulated Provision for Pensions and Benefits (228.3)	43,699,000	38,012,000	**94**
Accumulated Miscellaneous Operating Provisions (228.4)	758,420	1,574,773	**95**
Accumulated Provision for Rate Refunds (229)	7,648,474	9,790,412	**96**
Long-Term Portion of Derivative Instrument Liabilities (244)		0	**97**
Long-Term Portion of Derivative Instrument Liabilities - Hedges (245)	619	0	**98**
Asset Retirement Obligations (230)	85,863	85,416	**99**
Total Other Noncurrent Liabilities	**52,192,376**	**49,762,601**	
CURRENT AND ACCRUED LIABILITIES			
Notes Payable (231)	0	0	**100**
Accounts Payable (232)	33,481,123	39,180,399	**101**
Notes Payable to Associated Companies (233)	15,500,000	0	**102**
Accounts Payable to Associated Companies (234)	38,714,049	17,600,397	**103**
Customer Deposits (235)	1,999,221	1,930,030	**104**
Taxes Accrued (236)	761,590	7,979,441	**105**
Interest Accrued (237)	6,414,850	6,500,872	**106**
Dividends Declared (238)	8,522,302	8,582,690	**107**
Matured Long-Term Debt (239)	0	0	**108**
Matured Interest (240)	0	0	**109**
Tax Collections Payable (241)	1,402,344	1,252,858	**110**
Miscellaneous Current and Accrued Liabilities (242)	7,605,801	5,922,300	**111**
Obligations Under Capital Leases-Current (243)		0	**112**
Derivative Instrument Liabilities (244)		203,625	**113**

BALANCE SHEET

Liabilities and Other Credits (a)	Balance End of Year (b)	Balance First of Year (c)	
CURRENT AND ACCRUED LIABILITIES			
(Less) Long-Term Portion of Derivative Instrument Liabilities (244)		0	**114**
Derivative Instrument Liabilities - Hedges (245)	20,073	1,665,223	**115**
(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges (245)	619	0	**116**
Total Current and Accrued Liabilities	**114,420,734**	**90,817,835**	
DEFERRED CREDITS			
Customer Advances for Construction (252)	16,672,253	17,624,304	**117**
Accumulated Deferred Investment Tax Credits (255)	9,732,075	10,365,931	**118**
Deferred Gains from Disposition of Utility Plant (256)		0	**119**
Other Deferred Credits (253)	98,700,234	69,258,103	**120**
Other Regulatory Liabilities (254)	29,757,720	9,688,649	**121**
Unamortized Gain on Reaquired Debt (257)	0	0	**122**
Accumulated Deferred Income Taxes-Accel. Amort. (281)	450,868	0	**123**
Accumulated Deferred Income Taxes-Other Property (282)	199,672,457	182,762,456	**124**
Accumulated Deferred Income Taxes-Other (283)	81,090,298	67,452,862	**125**
Total Deferred Credits	**436,075,905**	**357,152,305**	
Total Liabilities and Other Credits	**1,463,090,046**	**1,387,861,121**	

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.

None

2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particluars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.

None

3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.

None

4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.

None

5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to such arrangements, etc.

None

6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity date of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.

Short-term borrowings are authorized by the Public Service Commission of Wisconsin (PSCW) Certificate of Authority and Order in Docket Nos. 4220-SB-129 and 4220-AU-135. On July 3, 2009, the PSCW approved NSP-Wisconsin's application to extend its authorized short-term debt limit of $100 million and continued short-term borrowing from NSP-Minnesota. The PSCW approved extension expires on June 30, 2012.

Long-term borrowings are authorized by the PSCW. In the PSCW Certificate of Authority and Order in Docket No. 4220-SB-128 (effective Apr. 11, 2008), the PSCW provided authorization for NSP-Wisconsin to issue up to $250 million aggregate principal amount for the purpose of redeeming or refinancing existing long-term debt, repaying short-term debt, and for other corporate utility purposes. In September 2008, NSP-Wisconsin issued $200 million of 6.375 percent First Mortgage Bonds due Sept. 1, 2038. A portion of the proceeds was used to meet the Oct. 1, 2008 maturity of $80 million of 7.64 percent Senior Notes and to prefund the early redemption of $65 million 7.375 percent First Mortgage Bonds on March 1, 2009.

7. Changes in articles of incorporation or amendments to charter. Explain the nature and purpose of such changes or amendments.

None

8. State the estimated annual effect and nature of any important wage scale changes during the year.

2009 Annual Salary Increase:
1) Union Employees - Based wage increase of 3.50 percent.
2) Non-Union Employees - Merit base increase of 2.00 percent effective July 1, 2009.

9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings completed during the year.

See Note 5 to the Financial Satements for discussion of legal contingencies.

10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.

None

11. (Reserved)

Not applicable

12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page or in the Appendix.

None

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.

The following changes in officers occurred during 2009.

Raymond E. Gogel resigned as Vice President on April 10, 2009.

David M. Sparby was elected Director, Vice President and Chief Financial Officer of NSP-Wisconsin, effective Aug. 26, 2009.

Benjamin G.S. Fowke III resigned as Chief Financial Officer of NSP-Wisconsin, effective Aug. 26, 2009. He retained his title of Vice President of NSP-Wisconsin.

Marvin E. McDaniel was elected as Vice President of NSP-Wisconsin, effective Aug. 26, 2009.

David M. Wilks resigned as Vice President of NSP-Wisconsin on March 31, 2010.

Kent T. Larson was elected as Vice President of NSP-Wisconsin on March 31, 2010.

14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

None

STATEMENT OF RETAINED EARNINGS

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or apropriated as well as the totals eventually to be accumulated.

Item (a)	Contra Primary Account Affected (b)	Amount (c)	
UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
Balance Beginning of Year		226,080,019	1
Changes			2
Adjustments to Retained Earnings (Account 439)			3
			4
			5
			6
			7
			8
TOTAL Credits to Retained Earnings (Acct. 439)			9
			10
			11
			12
			13
			14
TOTAL Debits to Retained Earnings (Acct. 439)			15
Balance Transferred from Income (Account 433 less Account 418.1)		47,392,562	16
Appropriations of Retained Earnings (Acct. 436)			17
Amortization Reserve - Federal		(923,724)	18
			19
			20
			21
TOTAL Appropriations of Retained Earnings (Acct. 436)		**(923,724)**	22
Dividends Declared-Preferred Stock (Account 437)			23
			24
			25
			26
			27
			28
TOTAL Dividends Declared-Preferred Stock (Account 437)			29
Dividends Declared-Common Stock (Account 438)			30
		(34,198,070)	31
			32
			33
			34
			35
TOTAL Dividends Declared-Common Stock (Account 438)		**(34,198,070)**	36

STATEMENT OF RETAINED EARNINGS

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or apropriated as well as the totals eventually to be accumulated.

Item (a)	Contra Primary Account Affected (b)	Amount (c)	
Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216.1	38,053	**37**
Balance - End of Year (Total 1, 9, 15, 16, 22, 29, 36, 37)		**238,388,840**	**38**
APPROPRIATED RETAINED EARNINGS (Account 215)			
			39
			40
			41
			42
			43
			44
TOTAL Appropriated Retained Earnings (Account 215)			**45**
APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		13,074,535	**46**
TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45, 46)		**13,074,535**	**47**
TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47)		**251,463,375**	**48**
UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
Balance-Beginning of Year (Debit or Credit)		2,539,110	**49**
Equity in Earnings for Year (Credit) (Account 418.1)		(29,642)	**50**
Less: Dividends Received (Debit)		38,053	**51**
			52
Balance-End of Year (Total lines 49 thru 52)		**2,471,415**	**53**

STATEMENT OF RETAINED EARNINGS

Statement of Retained Earnings (Page F-06)

General footnotes

STATEMENT OF CASH FLOWS

1. Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Description (a)	Amount (b)		
Net Cash Flow from Operating Activities:			1
Net Income	47,362,920		2
Noncash Charges (Credits) to Income:			3
Depreciation and Depletion	60,238,580		4
Amortization of Premium, Discount and Debt Expense	1,052,255		5
Amortization of Deferred Debits/Credits	1,385,936		6
			7
Deferred Income Taxes (Net)	8,355,397		8
Investment Tax Credit Adjustment (Net)	(633,856)		9
Net (Increase) Decrease in Receivables	(13,332,309)	*	10
Net (Increase) Decrease in Inventory	11,036,163		11
Net (Increase) Decrease in Allowances Inventory	(2,990)		12
Net Increase (Decrease) in Payables and Accrued Expenses	8,421,180		13
Net (Increase) Decrease in Other Regulatory Assets	7,049,399		14
Net (Increase) Decrease in Other Regulatory Liabilities	16,768,109		15
(Less) Allowance for Other Funds Used During Construction	1,421,031		16
(Less) Undistributed Earnings from Subsidiary Companies	(67,696)		17
Other (provide details in footnote):	(2,268,053)	*	18
Other: Net Realized and Unrealized Hedging Derivative Transactions	1,143,861		19
Other: Changes in Other Assets and Deferred Amounts	(1,558,540)		20
Other: Changes in Other Current Assets and Liabilties	(11,622,645)		21
Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	**132,042,072**		22
			23
Cash Flows from Investment Activities:			24
Construction and Acquisition of Plant (including land):			25
Gross Additions to Utility Plant (less nuclear fuel)	(99,671,606)		26
Gross Additions to Nuclear Fuel			27
Gross Additions to Common Utility Plant	(5,663,074)		28
Gross Additions to Nonutility Plant	(11,778)		29
(Less) Allowance for Other Funds Used During Construction	(1,421,031)		30
Other (provide details in footnote):			31
			32
			33
Cash Outflows for Plant (Total of lines 26 thru 33)	**(103,925,427)**		34
			35
Acquisition of Other Noncurrent Assets (d)			36
Proceeds from Disposal of Noncurrent Assets (d)			37
			38

STATEMENT OF CASH FLOWS

1. Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Description (a)	Amount (b)	
Investments in and Advances to Assoc. and Subsidiary Companies		39
Contributions and Advances from Assoc. and Subsidiary Companies		40
Disposition of Investments in (and Advances to)		41
Associated and Subsidiary Companies		42
		43
Purchase of Investment Securities (a)		44
Proceeds from Sales of Investment Securities (a)		45
Loans Made or Purchased		46
Collections on Loans		47
		48
Net (Increase) Decrease in Receivables		49
Net (Increase) Decrease in Inventory		50
Net (Increase) Decrease in Allowances Held for Speculation		51
Net Increase (Decrease) in Payables and Accrued Expenses		52
Other (provide details in footnote):		53
Miscellaneous Other Investing Activities	5,027,496	54
		55
Net Cash Provided by (Used in) Investing Activities		56
Total of lines 34 thru 55)	**(98,897,931)**	57
		58
Cash Flows from Financing Activities:		59
Proceeds from Issuance of:		60
Long-Term Debt (b)		61
Preferred Stock		62
Common Stock		63
Other (provide details in footnote):	21,796,879 *	64
Proceeds from notes payable to affiliate	62,500,000	65
Net Increase in Short-Term Debt (c)		66
Other (provide details in footnote):		67
		68
		69
Cash Provided by Outside Sources (Total 61 thru 69)	**84,296,879**	70
		71
Payments for Retirement of:		72
Long-term Debt (b)	(66,842,706)	73
Preferred Stock		74
Common Stock		75
Other (provide details in footnote):		76

STATEMENT OF CASH FLOWS

1. Codes to be used: (a) Net Proceeds or Payments; (b) Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Description (a)	Amount (b)	
Repayments of notes payable to affiliate	(47,000,000)	**77**
Net Decrease in Short-Term Debt (c)		**78**
		79
Dividends on Preferred Stock		**80**
Dividends on Common Stock	(34,258,458)	**81**
Net Cash Provided by (Used in) Financing Activities		**82**
(Total of lines 70 thru 81)	**(63,804,285)**	**83**
		84
Net Increase (Decrease) in Cash and Cash Equivalents		**85**
(Total of lines 22, 57 and 83)	**(30,660,144)**	**86**
		87
Cash and Cash Equivalents at Beginning of Year	30,988,973	**88**
		89
Cash and Cash Equivalents at End of Year	328,829	**90**

STATEMENT OF CASH FLOWS

Statement of Cash Flows (Page F-07)

General footnotes

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Line 10 -
2009 Change in Accounts Receivable
Provision for bad debts          $  4,505,632
Change in accounts receivable    $(17,837,941)
Total                            $(13,332,309)

Line 18 - (Increase)/Decrease in Accrued Utility Revenues
Line 64 - Capital Contributions by Parent
```

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b) (c) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges," report the accounts affected and the related amounts in a footnote.

Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)		
Balance of Account 219 at Beginning of Preceding Year	0	0	0	*	1
Preceding Year Reclassification from Account 219 to Net Income	0	0	0		2
Preceding Year Changes in Fair Value	0	0	0		3
Total (lines 2 and 3)	**0**	**0**	**0**		4
Balance of Account 219 at End of Preceding Year	**0**	**0**	**0**		5
Balance of Account 219 at Beginning of Current Year	0	0	0		6
Current Year Reclassifications from Account 219 to Net Income					7
Current Year Changes in Fair Value					8
Total (lines 7 and 8)	**0**	**0**	**0**		9
Balance of Account 219 at End of Current Year	**0**	**0**	**0**		10

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES (cont.)

Other Adjustments (e)	Other Cash Flow Hedges (Financial Swaps for Gas) (f)	Other Cash Flow Hedges (Specify in Footnote) (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (i)	Total Comprehensive Income (j)		
0	0	(819,963)	(819,963)			*	1
0	0	78,239	78,239				2
0	0	0	0				3
0	**0**	**78,239**	**78,239**	**45,520,685**	**45,598,924**		4
0	**0**	**(741,724)**	**(741,724)**				5
0	0	(741,724)	(741,724)				6
		76,069	76,069				7
			0				8
0	**0**	**76,069**	**76,069**	47,362,920	47,438,989		9
0	**0**	**(665,655)**	**(665,655)**				10

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Statements of Accumulated Comprehensive Income, Comprehensive Income, and Hedging Activities (Page F-08)

General footnotes

Amounts in column G relate to Other Cash Flow Hedges, Interest Rate Swaps.

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES (cont.)

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RETURN ON COMMON EQUITY AND COMMON STOCK EQUITY PLUS ITC COMPUTATIONS

1. Report data on a corporate basis only; not a consolidated basis.
2. If you file monthly rate of return forms with the PSC, use the same method for completing this form.
3. Use the average of the 12 monthly averages when computing average common equity.
4. If monthly averages are not available, use average of first of year and end of year.

Description (a)		Common Equity (b)	Common Equity Plus ITC (c)	
Average Common Equity				
Common Stock Outstanding		93,300,000	93,300,000	1
Premium on Capital Stock	based on monthly	33,337,651	33,337,651	2
Capital Stock Expense	averages if available			3
Retained Earnings		238,699,397	238,699,397	4
Deferred Investment Tax Credit				5
(Only common equity portion if Form PSC-AF6 is filed on monthly basis with the Commission)				
Other (Specify):				
PAID IN CAPITAL		93,846,813	93,846,813	6
Average Common Stock Equity		**459,183,861**	**459,183,861**	
Net Income				
Add:				
Net Income (or Loss)		47,362,920	47,362,920	7
Other (Specify):				
NONE				8
Less:				
Preferred Dividends				9
Other (Specify):				
(If Form PSC-AF6 is filed with the Commission, net income must be reduced by that portion of net income representing debt cost of deferred investment tax credit as shown on the form.)				
NONE			273,000	10
Adjusted Net Income (Loss)		**47,362,920**	**47,089,920**	
Percent Return on Common Stock Equity		**10.31%**	**10.26%**	

RETURN ON RATE BASE COMPUTATION

1. Report data on a corporate basis only; not a consolidated basis.
2. The data used in calculating average rate base are based on monthly averages, if available.
3. If you file monthly rate of return forms (PSC-AF4) with the PSC, use the same method for completing this schedule.
4. If monthly averages are not available, use average of the first-of-year and the end-of-year figures for each account.
5. Do not include property held for future use or construction work in progress with utility plant in service.
   These are not rate base components.

Average Rate Base (a)	Electric (b)	Gas (c)	Water (d)	Other (e)	Total (f)	
Add Average:						
Utility Plant in Service	1,449,675,939	180,315,694			**1,629,991,633**	1
Allocation of Common Plant	91,923,223	11,317,032			**103,240,255**	2
Completed Construction Not Classified					**0**	3
Gas Stored Underground		6,731,402			**6,731,402**	4
Nuclear Fuel					**0**	5
Materials and Supplies	16,866,112	2,063,393			**18,929,505**	6
Other (Specify):						
REGULATORY ASSETS EXCESS AFDC	3,392,089	444,131			**3,836,220**	7
Less Average:						
Reserve for Depreciation	751,593,021	107,353,884			**858,946,905**	8
Amortization Reserves	2,282,643				**2,282,643**	9
Customer Advances for Construction	15,373,270	2,265,074			**17,638,344**	10
Contribution in Aid of Construction					**0**	11
Accumulated Deferred Income Taxes	145,706,130	11,554,922			**157,261,052**	12
Other (Specify):						
APPROPRIATED RETAINED EARNINGS	12,087,486				**12,087,486**	13
Average Net Rate Base	**634,814,813**	**79,697,772**	**0**	**0**	**714,512,585**	
Total Operating Income (or Loss)	60,896,745	6,606,464	0		**67,503,209**	14
Less (Specify):						
NONE					**0**	15
Adjusted Operating Income	**60,896,745**	**6,606,464**	**0**	**0**	**67,503,209**	
Adjusted Operating Income as a percent of Average Net Rate Base	**9.59%**	**8.29%**	**N/A**	**N/A**	**9.45%**	

REVENUES SUBJECT TO WISCONSIN REMAINDER ASSESSMENT

1. Report data necessary to calculate revenue subject to Wisconsin remainder assessment.
2. Wholesale and retail out-of-state energy and water sales revenues are considered assessable due to the strong nexus to Wisconsin founded on the location of the generation facilities in the state and significant regulatory oversight by the Commission.
3. Exclude retail out-of-state energy sales where energy is both produced and sold out-of-state.

Description (a)	Electric Utility (b)	Gas Utility (c)	Water Utility (d)	Other Utility (e)	Total (f)	
Operating revenues	561,690,877	132,478,834	0	214,655	**694,384,366**	1
Less: out-of-state operating revenues					**0**	2
Less: in-state interdepartmental sales	143,960	1,042,030			**1,185,990**	3
Less: current year write-offs of uncollectible accounts (Wisconsin utility customers only)	3,816,294	1,557,489			**5,373,783**	4
Plus: current year collection of Wisconsin utility customer accounts previously written off	739,202	301,680			**1,040,882**	5
Other Increases or (Decreases) to Operating Revenues - Specify: NONE					**0**	6
Revenues subject to Wisconsin Remainder Assessment	**558,469,825**	**130,180,995**	**0**	**214,655**	**688,865,475**	

AFFILIATED INTEREST TRANSACTIONS

Intercompany Transactions from utility to Associated Companies

Department (a)	Hours Paid (b)	Total Costs (including Overheads) (c)	Total Billing (d)	Markup for Fair Market Value (e)	
Labor					
Community Service			536	**536**	**1**
Distribution Utility - Construction			100,107	**100,107**	**2**
Distribution Utility - Design North			408	**408**	**3**
Distribution Utility - Jurisdiction			1,642	**1,642**	**4**
Energy Supply			125,383	**125,383**	**5**
Meter Reading			63,002	**63,002**	**6**
Substation Engineering & Design			40,183	**40,183**	**7**
Transmission Engineering			193	**193**	**8**
				0	**9**
				0	**10**
				0	**11**
				0	**12**
				0	**13**
				0	**14**
				0	**15**
Total Labor	**0**	**0**	**331,454**	**331,454**	
Other					
Interchange Agreement Billings to NSPM			109,251,587	**109,251,587**	**16**
Shared Asset Costs			2,147,688	**2,147,688**	**17**
Contract Labor and Consulting			273,655	**273,655**	**18**
Lease Revenue Chippewa Flambeau Improvement			214,655	**214,655**	**19**
DSM Promotion			133,452	**133,452**	**20**
Asset Transfers			131,107	**131,107**	**21**
Materials and Supplies			84,181	**84,181**	**22**
License Fees & Permits			38,440	**38,440**	**23**
Employee Expenses			34,698	**34,698**	**24**
Legal			20,253	**20,253**	**25**
Rent & Lease Costs			10,899	**10,899**	**26**
Audit Fees			20,000	**20,000**	**27**
Company Vehicles			2,708	**2,708**	**28**
Personal Auto			1,451	**1,451**	**29**
Postage			1,096	**1,096**	**30**
Professional Association Dues			129	**129**	**31**
Other			(149,683)	**(149,683)**	**32**
				0	**33**
				0	**34**
				0	**35**
				0	**36**
Total Other	**0**	**0**	**112,216,316**	**112,216,316**	
Total:	**0**	**0**	**112,547,770**	**112,547,770**	

AFFILIATED INTEREST TRANSACTIONS

Affiliated Interest Transactions (Page F-13)

General footnotes

Detail represents those billings from Northern States Power Company (Wisconsin) to Affiliates.

See appendix for additional information, including detail of intercompany charges from Xcel Energy Services to Northern States Power Company (Wisconsin) and detail of charges between Northern States Power Company (Wisconsin) and its Regulated Affiliates.

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Classification (a)	Total (b)	Electric (c)	
			1
Utility Plant in Service			2
Plant in Service(101,101.1)/Unclassified Completed Construction(106,major only)	**1,767,710,400**	1,479,771,314	3
Property Under Capital Leases	**0**		4
Plant Purchased or Sold	**0**		5
Completed Construction not Classified	**0**		6
Experimental Plant Unclassified	**0**		7
Total In Service	**1,767,710,400**	**1,479,771,314**	8
Leased to Others	**2,832,049**	2,832,049	9
Held for Future Use	**3,277,025**	3,277,025	10
Construction Work in Progress	**52,143,786**	44,311,958	11
Acquisition Adjustments	**0**		12
Total Utility Plant	**1,825,963,260**	**1,530,192,346**	13
Accum Prov for Depr, Amort, & Depl	**875,018,980**	714,911,527	14
Net Utility Plant	**950,944,280**	**815,280,819**	15
			16
Detail of Accum Prov for Depr, Amort & Depl in Service			17
Depreciation	**869,153,382**	709,050,866	18
Amort & Depl of Producing Nat Gas Land/land Right	**0**		19
Amort of Underground Storage Land/Land Rights	**0**		20
Amort of Other Utility Plant	**2,858,090**	2,853,153	21
Total In Service	**872,011,472**	**711,904,019**	22
Leased to Others			23
Depreciation	**973,357**	973,357	24
Amortization and Depletion	**0**		25
Total Leased to Others	**973,357**	**973,357**	26
Held for Future Use			27
Depreciation	**0**		28
Amortization	**0**		29
Total Held for Future Use	**0**	**0**	30
Abandonment of Leases (Natural Gas)	**0**		31
Amort of Plant Acquisition Adj	**0**		32
Total Accum Prov	**872,984,829**	**712,877,376**	33

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION (cont.)

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	
					1
					2
187,459,229				100,479,857	3
					4
					5
					6
					7
187,459,229	**0**	**0**	**0**	**100,479,857**	8
					9
0					10
1,131,127				6,700,701	11
					12
188,590,356	**0**	**0**	**0**	**107,180,558**	13
103,494,852				56,612,601	14
85,095,504	**0**	**0**	**0**	**50,567,957**	15
					16
					17
103,489,915				56,612,601	18
					19
					20
4,937					21
103,494,852	**0**	**0**	**0**	**56,612,601**	22
					23
					24
					25
0	**0**	**0**	**0**	**0**	26
					27
					28
					29
0	**0**	**0**	**0**	**0**	30
					31
					32
103,494,852	**0**	**0**	**0**	**56,612,601**	33

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion (Page F-14)

General footnotes

Plant In Service amounts are defaulted from pages E12-13 and G07-08, and therefore include Completed Construction not Classified. Therefore, in this schedule there are no amounts entered for the Completed Construction not Classified line.

FERC Form 1 pages 200-201, line 21, contains an amount of $2,034,151 for Amortization of Other Utility Plant (Account 111).

This page (F-14) defaults the value from page E14 on line 21 which is the Amort of Other Utility Plant line. Therefore there is not a line available to input the Account 111 amount.

Thus the difference between line 14 of $875,018,980 and line 33 of $872,984,829 for total company and $714,911,527 and $712,877,376 for Electric is the $2,034,151 of Account 111 Amortization.

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION (cont.)

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UTILITY PLANT HELD FOR FUTURE USE (ACCOUNT 105)

Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to Be Used in Utility Service (c)	Balance at End of Year (d)	
Electric				
Land and Rights:				
Various	Various	Various	33,563	**1**
Other Property:				
St. Croix Falls-Border (DPC)	2008	2010+	3,243,462	**2**
			3,277,025	
Total			**3,277,025**	

CONSTRUCTION WORK IN PROGRESS (ACCT. 107)

1. Report below descriptions and balances at beginning and end of year of projects in process of construction (107).
2. Minor projects under $1,000,000 major and under $500,000 nonmajor should be grouped by utility department and function.

Project Description (a)	Balance First of Year (b)	Balance End of Year (c)	
Electric			
Transmission Infrastructure Project-Line NSPW Wood Structures	0	1,040,563	**1**
Fleet Lease Buy Out-Northern States Power Wisconsin-Electric	0	1,007,444	**2**
WI Substation Construction	134,868	1,632,878	**3**
Chisago to Apple River WI 161KV Line	0	2,576,240	**4**
Three Lakes Substation	519,742	3,877,226	**5**
Repl Rush River 23.9 kv Sub	365,609	4,328,798	**6**
Gravel Island Sub	1,021,474	6,971,554	**7**
LaCrosse 161 kv Capacitors	365,854	7,014,885	**8**
DLL Dells Hydro Repowering Total	8,480,130	0	**9**
Minor Projects	3,071,650	15,862,370	**10**
Upgrade Willow River Bank 1 to	1,658,702	0	**11**
Ashland US Hwy 2 OH to UG Line Relocation	877,480	0	**12**
Fleet New Unit Purchase El Ops Total	792,428	0	**13**
Genoa-Coulee Structure, Line	757,996	0	**14**
NSPW 5-Year Line Blanket Autho	711,193	0	**15**
Ironwood 115kv Station Eq	313,799	0	**16**
RBL021 Relocate 2 miles of Line	274,598	0	**17**
Wheaton Sub	270,518	0	**18**
W3214 161kv Term Wheaton	261,473	0	**19**
Ironwood Addition 92/ 34.5kv 2	546,109	0	**20**
Electric Meter Blanket	369,982	0	**21**
Fleet New Unit Purchase El Ops	103,458	0	**22**
2005 WI Tran Line Relocation B	109,973	0	**23**
LDS3C-U3 Replace Governor Cont	113,765	0	**24**
Camp McCoy Bank #2	108,542	0	**25**
Engineering W.O.-Transmission Total	184,717	0	**26**
Prescott 69 kv Cap Bank	126,937	0	**27**
Osceola Cap Bank Addition	109,318	0	**28**
EM MISO Ancillary	170,852	0	**29**
Miscellaneous Network	108,774	0	**30**
Ironwood 3R15	296,172	0	**31**
EMS Dynamic-Heightened Reliability	179,130	0	**32**
DLLC0 Cooling Water System	218,523	0	**33**
SCADA Switch - Line 3352	284,330	0	**34**
Switches - Lines #3473	337,936	0	**35**
New Dual Secondary Service for Sacred Heart	201,594	0	**36**
FEN99C U99 Loader Purchase	100,929	0	**37**
Subtotal - Electric:	**23,548,555**	**44,311,958**	
Gas			
Minor Projects	105,804	1,131,127	**38**
Kinnickinick Capacity Utilization	1,338,957	0	**39**
Capital Transportation Blanket	627,065	0	**40**

CONSTRUCTION WORK IN PROGRESS (ACCT. 107)

1. Report below descriptions and balances at beginning and end of year of projects in process of construction (107).
2. Minor projects under $1,000,000 major and under $500,000 nonmajor should be grouped by utility department and function.

Project Description (a)	Balance First of Year (b)	Balance End of Year (c)	
Gas			
Fleet New Unit Purchase Gas Op	104,550	0	**41**
Wisc Urban-Gas Main Relocation	107,000	0	**42**
LNG Plant Blanket	236,708	0	**43**
Dylon Replacement Project-Inst	156,304	0	**44**
Subtotal - Gas:	**2,676,388**	**1,131,127**	
Water			
NONE	0	0	**45**
Subtotal - Water:	**0**	**0**	
Steam			
NONE	0	0	**46**
Subtotal - Steam:	**0**	**0**	
Common			
CS Building Renovation/Remodel	0	3,815,113	**47**
Minor Projects	835,482	2,885,588	**48**
PBX Skypark WI	1,379,484	0	**49**
Vista Microsoft	400,471	0	**50**
GIS 4.1 Transmission	331,132	0	**51**
MDT Standardization HW	252,548	0	**52**
Mobile Computing Emergency Response (Outage Management System)	293,058	0	**53**
DAMS/Mobile Computing - WI	208,215	0	**54**
Analytics Warehouse Ph2 Data Mart	109,044	0	**55**
Electronic Data Discovery	173,299	0	**56**
GIS v 4.1 (GATE) Dist	153,989	0	**57**
EM Trading Risk Mgmt Repl Pano	132,175	0	**58**
Subtotal - Unknown:	**4,268,897**	**6,700,701**	
Other			
NONE	0	0	**59**
Subtotal - Other:	**0**	**0**	
Total:	**30,493,840**	**52,143,786**	

CONSTRUCTION ACTIVITY FOR YEAR

Report below the total overheads and the total direct cost of construction for the year. Projects under $1,000,000 for major utilities and $500,000 for nonmajor utilities should be grouped by utility department and function.

Project Description (a)	Direct Charges: Company Labor (b)	Company Materials (c)	Contractor Payments (d)	Other (e)	
Electric					
Projects over $1,000,000	0	0	0	0	**1**
Electric Production	0	0	0	0	**2**
Dll4C - Hydro Rpwr-Unit 4	0	8,001	1,370,052	535,300	**3**
Dll5C - Hydro Rpwr-Unit 5	21,550	147,422	1,042,961	535,799	**4**
Dll0C - Hydro Rpwr-Common	2,227	(129,713)	(1,430,257)	68	**5**
Electric Transmission	0	0	0	0	**6**
Wheaton Sub 161KV Line Termination	575,924	616,447	130,280	188,766	**7**
Gis Gravel Island -New Substation	518,994	4,584,209	229,979	199,428	**8**
THL-Construct New Three Lakes Substation	384,562	2,366,029	166,887	118,241	**9**
W3213 WHT to RCD TAP Rebuild	130,253	623,876	178,786	54,344	**10**
Moc - Sub 161Kv Upgrade	(98,815)	(1,726,262)	(264,008)	(67,279)	**11**
LAX-Sub 161KV Cap bank Addition	311,104	623,804	249,162	138,239	**12**
SCF-Convert Sub to 161KV (TAM)	250,159	799,463	220,530	118,369	**13**
W3218 SCF-BDR Install 2.4 Miles - New	322,690	518,072	902,389	235,048	**14**
Moc - Sub 161Kv Upgrade	954,397	2,849,170	616,066	370,770	**15**
Electric Distribution	0	0	0	0	**16**
WLR-TR1 Upgrade to 70MVA	269,558	21,659	31,120	59,256	**17**
CPM-Install 2nd Transformer	408,281	321,231	141,899	87,238	**18**
WI Electric Cellnet Meters	19,166	1,940,625	571,732	183,648	**19**
Ebw-New Substation (Dam)	105,622	2,931,410	498,358	36,647	**20**
2008 UG Services Wisc Urban	580,977	791,556	42,109	449,866	**21**
2007 Dist Line Transformer Purchases for WI	0	0	0	4,472,751	**22**
2008 Dist Line Transformer Purchases for WI	0	0	0	4,736,381	**23**
Electric General	0	0	0	0	**24**
WI Electric Cellnet Modules	0	1,966,868	0	0	**25**
	0	0	0	0	**26**
Projects under $1,000,000	5,739,230	20,226,749	9,879,427	(3,254,473)	**27**
	0	0	0	0	**28**
Subtotal Electric:	**10,495,879**	**39,480,616**	**14,577,472**	**9,198,407**	
% of Subtotal Direct Charges:					
Gas					
Projects over $1,000,000	0	0	0	0	**29**
Gas Distribution	0	0	0	0	**30**
Kinnickinnic Reinforcement/Cty N & Hwy 65	77	29,223	26,131	(92)	**31**
2008 New Services Wisc Urban	541,861	186,308	470,831	474,921	**32**
2008 Svc Renew/Cutoff Wisc Urban	170,873	76,508	214,816	246,369	**33**
Gas Meters Purchased for WI in 2008	0	0	0	1,010,168	**34**
Gas General	0	0	0	0	**35**
WI Gas Cellnet Modules	0	4,593,518	0	0	**36**
					37
Projects under $1,000,000	473,870	1,763,557	1,598,493	(96,678)	**38**

CONSTRUCTION ACTIVITY FOR YEAR (cont.)

Total Direct Charges (f)	Overheads: Engineering & Supervision (g)	Administration & General (h)	Allowance for Funds Used (i)	Taxes & Other (j)	Total Direct Charges and Overheads (k)	
0	0	0	0	0	**0**	**1**
0	0	0	0	0	**0**	**2**
1,913,353	95,351	4,592	204,652	0	**2,217,948**	**3**
1,747,732	67,846	4,195	121,674	12,786	**1,954,233**	**4**
(1,557,675)	(97,547)	(3,738)	110,715	1,163	**(1,547,082)**	**5**
0	0	0	0	0	**0**	**6**
1,511,417	24,407	3,627	95,060	164,463	**1,798,974**	**7**
5,532,610	99,163	13,278	203,560	108,957	**5,957,568**	**8**
3,035,719	50,306	7,286	103,145	83,445	**3,279,901**	**9**
987,259	100,998	2,369	32,839	40,181	**1,163,646**	**10**
(2,156,364)	38,782	5,849	(2,165)	(195,342)	**(2,309,240)**	**11**
1,322,309	19,869	3,174	97,223	58,900	**1,501,475**	**12**
1,388,521	26,369	3,332	40,195	39,594	**1,498,011**	**13**
1,978,199	280,446	4,748	88,095	44,657	**2,396,145**	**14**
4,790,403	95,758	11,497	64,912	184,988	**5,147,558**	**15**
0	0	0	0	0	**0**	**16**
381,593	11,408	916	63,581	55,718	**513,216**	**17**
958,649	29,449	2,301	27,315	87,057	**1,104,771**	**18**
2,715,171		6,516		10,264	**2,731,951**	**19**
3,572,037	128,506	8,573	216,498	37,575	**3,963,189**	**20**
1,864,508	0	0	0	953,662	**2,818,170**	**21**
4,472,751	0	0	0	0	**4,472,751**	**22**
4,736,381	0	0	0	0	**4,736,381**	**23**
0	0	0	0	0	**0**	**24**
1,966,868	0	0	0	0	**1,966,868**	**25**
0	0	0	0	0	**0**	**26**
32,590,933	5,296,288	79,764	548,226	(3,199,356)	**35,315,855**	**27**
0	0	0	0	0	**0**	**28**
73,752,374	**6,267,399**	**158,279**	**2,015,525**	**(1,511,288)**	**80,682,289**	
	8.50%	**0.21%**	**2.73%**	**-2.05%**		
0	0	0	0	0	**0**	**29**
0	0	0	0	0	**0**	**30**
55,339	(780)	133	3,802	66	**58,560**	**31**
1,673,921	0	0	0	897,213	**2,571,134**	**32**
708,566	0	0	0	399,058	**1,107,624**	**33**
1,010,168	0	0	0	0	**1,010,168**	**34**
0	0	0	0	0	**0**	**35**
4,593,518	0	0	0	0	**4,593,518**	**36**
0					**0**	**37**
3,739,242	1,938,866	11,575	39,150	(894,572)	**4,834,261**	**38**

CONSTRUCTION ACTIVITY FOR YEAR

Report below the total overheads and the total direct cost of construction for the year. Projects under $1,000,000 for major utilities and $500,000 for nonmajor utilities should be grouped by utility department and function.

Project Description (a)	Direct Charges: Company Labor (b)	Company Materials (c)	Contractor Payments (d)	Other (e)	
Gas					
	0	0	0	0	**39**
Subtotal Gas:	**1,186,681**	**6,649,114**	**2,310,271**	**1,634,688**	
% of Subtotal Direct Charges:					
Water					
NONE					**40**
Subtotal Water:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Steam					
NONE					**41**
Subtotal Steam:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Common					
Projects over $1,000,000	0	0	0	0	**42**
Common General	0	0	0	0	**43**
PBX Skypark WI	46,803	(1,415)	253,418	113	**44**
CPM-Install 2nd Transformer	43,348	1,336,865	2,331,352	5,643	**45**
	0	0	0	0	**46**
Projects under $1,000,000	106,952	788,650	2,635,463	222,286	**47**
	0	0	0	0	**48**
Subtotal Common:	**197,103**	**2,124,100**	**5,220,233**	**228,042**	
% of Subtotal Direct Charges:					
Other					
Projects under $1,000,000				11,778	**49**
Subtotal Other:	**0**	**0**	**0**	**11,778**	
% of Subtotal Direct Charges:					
Grand Totals:	**11,879,663**	**48,253,830**	**22,107,976**	**11,072,915**	
% of Total Direct Charges:					

CONSTRUCTION ACTIVITY FOR YEAR (cont.)

Total Direct Charges (f)	Overheads: Engineering & Supervision (g)	Administration & General (h)	Allowance for Funds Used (i)	Taxes & Other (j)	Total Direct Charges and Overheads (k)	
0	0	0	0	0	**0**	**39**
11,780,754	**1,938,086**	**11,708**	**42,952**	**401,765**	**14,175,265**	
	16.45%	**0.10%**	**0.36%**	**3.41%**		
0					**0**	**40**
0	**0**	**0**	**0**	**0**	**0**	
0					**0**	**41**
0	**0**	**0**	**0**	**0**	**0**	
0	0	0	0	0	**0**	**42**
0	0	0	0	0	**0**	**43**
298,919	0	(176)	0	17,751	**316,494**	**44**
3,717,208		8,921	58,678	23,698	**3,808,505**	**45**
0	0	0	0	0	**0**	**46**
3,753,351	0	3,267	172,190	41,071	**3,969,879**	**47**
0	0	0	0	0	**0**	**48**
7,769,478	**0**	**12,012**	**230,868**	**82,520**	**8,094,878**	
	0.00%	**0.15%**	**2.97%**	**1.06%**		
11,778					**11,778**	**49**
11,778	**0**	**0**	**0**	**0**	**11,778**	
	0.00%	**0.00%**	**0.00%**	**0.00%**		
93,314,384	**8,205,485**	**181,999**	**2,289,345**	**(1,027,003)**	**102,964,210**	
	8.79%	**0.20%**	**2.45%**	**-1.10%**		

CONSTRUCTION ACTIVITY FOR YEAR

Construction Activity for Year (Page F-18)

General footnotes

CONSTRUCTION ACTIVITY FOR YEAR (cont.)

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CONSTRUCTION COMPLETED DURING YEAR

Report below the total cost of completed construction projects cleared from account 107 during the year. Projects under $1,000,000 for major utilities and $500,000 for nonmajor utilities should be grouped by utility department and function.

Project Description (a)	Direct Charges: Company Labor (b)	Company Materials (c)	Contractor Payments (d)	Other (e)	
Electric					
Projects over $1,000,000	0	0	0	0	**1**
Electric Production	0	0	0	0	**2**
Dll4C - Hydro Rpwr-Unit 4	0	2,461,208	2,258,811	535,300	**3**
Dll5C - Hydro Rpwr-Unit 5	28,606	926,384	1,069,231	536,031	**4**
Dll0C - Hydro Rpwr-Common	24,364	667,521	274,741	6,083	**5**
Electric Transmission	0	0	0	0	**6**
Wheaton Sub 161KV Line Termination	609,289	771,712	174,376	189,590	**7**
W3213 WHT to RCD TAP Rebuild	144,078	623,876	205,567	56,042	**8**
Moc - Sub 161Kv Upgrade	(98,815)	(1,726,262)	(264,008)	(67,279)	**9**
Electric Distribution	0	0	0	0	**10**
WLR-TR1 Upgrade to 70MVA	486,682	1,140,577	81,103	88,026	**11**
CPM-Install 2nd Transformer	425,303	366,542	164,667	88,040	**12**
WI Electric Cellnet Meters	19,166	1,940,625	571,732	183,648	**13**
2008 UG Services Wisc Urban	580,977	791,556	42,109	449,866	**14**
2007 Dist Line Transformer Purchases for WI				4,472,751	**15**
2008 Dist Line Transformer Purchases for WI	0	0	0	4,736,381	**16**
Electric General	0	0	0	0	**17**
WI Electric Cellnet Modules	0	1,966,868	0	0	**18**
	0	0	0	0	**19**
Projects under $1,000,000	4,819,750	15,710,471	9,023,898	(3,176,786)	**20**
	0	0	0	0	**21**
Subtotal Electric:	**7,039,400**	**25,641,078**	**13,602,227**	**8,097,693**	
% of Subtotal Direct Charges:					
Gas					
Projects over $1,000,000	0	0	0	0	**22**
Gas Distribution	0	0	0	0	**23**
Kinnickinnic Reinforcement/Cty N & Hwy 65	21,235	557,974	606,217	6,783	**24**
2008 New Services Wisc Urban	541,861	186,308	470,830	474,921	**25**
2008 Svc Renew/Cutoff Wisc Urban	170,873	76,508	214,816	246,369	**26**
Gas Meters Purchased for WI in 2008	0	0	0	1,010,168	**27**
Gas General	0	0	0	0	**28**
WI Gas Cellnet Modules	0	4,593,518	0	0	**29**
	0	0	0	0	**30**
Projects under $1,000,000	512,688	2,079,268	1,371,810	(24,827)	**31**
	0	0	0	0	**32**
Subtotal Gas:	**1,246,657**	**7,493,576**	**2,663,673**	**1,713,414**	
% of Subtotal Direct Charges:					

CONSTRUCTION COMPLETED DURING YEAR (cont.)

Total Direct Charges (f)	Overheads: Engineering & Supervision (g)	Overheads: Administration & General (h)	Overheads: Allowance for Funds Used (i)	Overheads: Taxes & Other (j)	Overheads: Total Direct Charges and Overheads (k)	
0	0	0	0	0	0	1
0	0	0	0	0	0	2
5,255,319	135,965	11,456	384,102	(6)	5,786,836	3
2,560,252	78,990	5,878	173,549	16,353	2,835,022	4
972,709	(31,596)	4,249	414,153	20,804	1,380,319	5
0	0	0	0	0	0	6
1,744,967	37,099	3,956	97,989	182,100	2,066,111	7
1,029,563	103,545	2,466	35,466	48,182	1,219,222	8
(2,156,364)	38,782	5,849	(2,165)	(195,342)	(2,309,240)	9
0	0	0	0	0	0	10
1,796,388	154,735	2,845	95,938	122,010	2,171,916	11
1,044,552	40,081	2,439	30,102	96,139	1,213,313	12
2,715,171	0	6,516	0	10,264	2,731,951	13
1,864,508	0	0	0	953,662	2,818,170	14
4,472,751					4,472,751	15
4,736,381	0	0	0	0	4,736,381	16
0	0	0	0	0	0	17
1,966,868	0	0	0	0	1,966,868	18
0	0	0	0	0	0	19
26,377,333	5,050,570	63,030	581,797	(3,243,464)	28,829,266	20
0	0	0	0	0	0	21
54,380,398	5,608,171	108,684	1,810,931	(1,989,298)	59,918,886	
	10.31%	0.20%	3.33%	-3.66%		
0	0	0	0	0	0	22
0	0	0	0	0	0	23
1,192,209	162,421	1,878	12,706	8,942	1,378,156	24
1,673,920	0	0	0	897,213	2,571,133	25
708,566	0	0	0	399,058	1,107,624	26
1,010,168	0	0	0	0	1,010,168	27
0	0	0	0	0	0	28
4,593,518	0	0	0	0	4,593,518	29
0	0	0	0	0	0	30
3,938,939	1,950,363	12,423	28,089	(869,887)	5,059,927	31
0	0	0	0	0	0	32
13,117,320	2,112,784	14,301	40,795	435,326	15,720,526	
	16.11%	0.11%	0.31%	3.32%		

CONSTRUCTION COMPLETED DURING YEAR

Report below the total cost of completed construction projects cleared from account 107 during the year. Projects under $1,000,000 for major utilities and $500,000 for nonmajor utilities should be grouped by utility department and function.

Project Description (a)	Direct Charges: Company Labor (b)	Direct Charges: Company Materials (c)	Direct Charges: Contractor Payments (d)	Direct Charges: Other (e)	
Water					
NONE					33
Subtotal Water:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Steam					
NONE					34
Subtotal Steam:	**0**	**0**	**0**	**0**	
% of Subtotal Direct Charges:					
Common					
					35
Projects over $1,000,000	0	0	0	0	36
Common General	0	0	0	0	37
PBX Skypark WI	67,156	35,057	1,563,672	438	38
	0	0	0	0	39
Projects under $1,000,000	104,270	392,840	3,043,455	197,235	40
Subtotal Common:	**171,426**	**427,897**	**4,607,127**	**197,673**	
% of Subtotal Direct Charges:					
Other					
Projects under $1,000,000				11,778	41
Subtotal Other:	**0**	**0**	**0**	**11,778**	
% of Subtotal Direct Charges:					
Grand Totals:	**8,457,483**	**33,562,551**	**20,873,027**	**10,020,558**	
% of Total Direct Charges:					

CONSTRUCTION COMPLETED DURING YEAR (cont.)

Total Direct Charges (f)	Overheads: Engineering & Supervision (g)	Administration & General (h)	Allowance for Funds Used (i)	Taxes & Other (j)	Total Direct Charges and Overheads (k)	
0					**0**	33
0	**0**	**0**	**0**	**0**	**0**	
0					**0**	34
0	**0**	**0**	**0**	**0**	**0**	
0					**0**	35
0	0	0	0	0	**0**	36
0	0	0	0	0	**0**	37
1,666,323	0	1,273	0	28,382	**1,695,978**	38
0	0	0	0	0	**0**	39
3,737,800	0	2,342	191,306	35,648	**3,967,096**	40
5,404,123	**0**	**3,615**	**191,306**	**64,030**	**5,663,074**	
	0.00%	**0.07%**	**3.54%**	**1.18%**		
11,778					**11,778**	41
11,778	**0**	**0**	**0**	**0**	**11,778**	
	0.00%	**0.00%**	**0.00%**	**0.00%**		
72,913,619	**7,720,955**	**126,600**	**2,043,032**	**(1,489,942)**	**81,314,264**	
	10.59%	**0.17%**	**2.80%**	**-2.04%**		

INVESTMENTS AND FUNDS (ACCTS. 123-128, INCL.)

1. Report with separate descriptions for each amount, the securities owned by the utility; include date of issue and date of maturity in description of any debt securities owned.
2. Designate any securities pledged and explain purpose of pledge in footnote.
3. Invesments less than $1,000 may be grouped by classes.
4. Report separately each fund account showing nature of assets included therein and list any securities included in fund accounts.

Description (a)	Date Acquired (b)	Maturity Date (c)		
Acct. 123 - Investment in Associated Companies				
				1
Acct. 123.1 - Investment in Subsidiary Companies				
Chippewa and Flambeau Improvement Company - Capital Stock			*	2
Equity in undistributed earnings				3
Clearwater Investments, Inc. - Capital Stock	6/1/1992			4
Equity in undistributed earnings				5
NSP Lands, Inc. - Capital Stock	6/1/1992			6
Equity in undistributed earnings				7
Acct. 124 - Other Investments				
Economic Development Loans			*	8
Life Insurance Investments			*	9
Acct. 125 - Sinking Funds				
				10
Acct. 126 - Depreciation Fund				
				11
Acct. 127 - Amortization Fund - Federal				
				12
Acct. 128 - Other Special Funds				
Red Cedar River Enhancement Fund			*	13

INVESTMENTS AND FUNDS (ACCTS. 123-128, INCL.) (cont.)

	Amount of Investment at Beginning Of Year (d)	Equity in Subsidiary Earnings Of Year (e)	Revenues For Year (f)	Amount of Investment at End Of Year (g)	Gain or Loss From Investment Disposed Of (h)	
Acct. 123 - Investment in Associated Companies						
				0		**1**
Acct. 123 Subtotal:	**0**	**0**	**0**	**0**	**0**	
Acct. 123.1 - Investment in Subsidiary Companies						
	549,326			**549,326**		* **2**
	157,971	38,354	(38,053)	**158,272**		**3**
	150,000			**150,000**		**4**
	2,041,161	(44,003)		**1,997,158**		**5**
	50,000			**50,000**		**6**
	339,978	(23,994)		**315,984**		**7**
Acct. 123.1 Subtotal:	**3,288,436**	**(29,643)**	**(38,053)**	**3,220,740**	**0**	
Acct. 124 - Other Investments						
	3,375,663		(100,660)	**3,275,003**		* **8**
	478,417		304,715	**783,132**		* **9**
Acct. 124 Subtotal:	**3,854,080**	**0**	**204,055**	**4,058,135**	**0**	
Acct. 125 - Sinking Funds						
				0		**10**
Acct. 125 Subtotal:	**0**	**0**	**0**	**0**	**0**	
Acct. 126 - Depreciation Fund						
				0		**11**
Acct. 126 Subtotal:	**0**	**0**	**0**	**0**	**0**	
Acct. 127 - Amortization Fund - Federal						
				0		**12**
Acct. 127 Subtotal:	**0**	**0**	**0**	**0**	**0**	
Acct. 128 - Other Special Funds						
	74,063		(22,637)	**51,426**		* **13**
Acct. 128 Subtotal:	**74,063**	**0**	**(22,637)**	**51,426**	**0**	
Total:	**7,216,579**	**(29,643)**	**143,365**	**7,330,301**	**0**	

INVESTMENTS AND FUNDS (ACCTS. 123-128, INCL.)

Investments and Funds (Accts. 123-128, incl.) (Page F-22)

General footnotes

2. Capital stock for Chippewa and Flambeau Improvement Company was acquired through various purchases and stock dividends between September 20, 1926 and August 10, 1992.

8. $100,000 principal repaid, $660 principal forgiven on Economic Development loans during 2009.

9. Represents a $304,715 increase in the value of Northern States Power Company (Wisconsin)'s life insurance investments during 2009.

13. As part of the settlement agreement related to the relicensing of Northern States Power Company (Wisconsin)'s hydro projects on the Red Cedar River, Northern States Power Company (Wisconsin) established the Red Cedar River Enhancement Fund. The Red Cedar River Enhancement Fund will be used in the Lower Red Cedar River Basin to fund environmental protection, mitigation, restoration or educational activities and studies, fish protection measures, and other environmental measures deemed appropriate. During 2009, two projects were funded. The partnership for Conservation Implementation sponsored by River Country RC&D Council, Inc. was awarded $15,363. The Galloway Creek Watershed Project sponsored by UW Stout was awarded $7,680. Interest was earned on the fund during 2009 totaling $406.

INVESTMENTS AND FUNDS (ACCTS. 123-128, INCL.) (cont.)

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ACCOUNTS RECEIVABLE (ACCTS. 142-143)

Particulars (a)	Amount End of Year (b)		
Customer Accounts Receivable (142)			
Electric department	41,032,142	*	1
Gas department	13,229,581	*	2
Water department			3
Steam department			4
Other			5
Total Utility Service:	**54,261,723**		
Merchandising, jobbing and contract work			6
Other			7
Total (Acct. 142):	**54,261,723**		
Other Accounts Receivable (143)			
Officers and employees	49,568		8
Subscriptions to capital stock			9
All other (list separately items in excess of $250,000; group remaining items as Miscellaneous):			
Miscellaneous	310,779		10
Total (Acct. 143):	**360,347**		

ACCOUNTS RECEIVABLE (ACCTS. 142-143)

Accounts Receivable (Accts. 142-143) (Page F-24)

General footnotes

1.& 2. Customer accounts receivable allocation to electric and gas utility is an estimate based on November and December 2009 calender month sales.

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR (ACCT. 144)

Particulars (a)	Electric Utility Customers (b)	Gas Utility Customers (c)	Water Utility Customers (d)	Steam Utility Customers (e)	Other Utility Customers (f)	
Balance First of Year	3,165,384	1,305,258	0	0	0	1
Add: provision for uncollectibles during year						
Provision for uncollectibles during year	3,171,727	1,105,670				* 2
Collection of accts prev written off: Utility Customers	739,202	301,680				3
Other credits (explain in footnotes)						4
Total Credits:	**3,910,929**	**1,407,350**	**0**	**0**	**0**	
Less: Accounts written off						
Accounts written off during the year: Utility Customers	3,816,294	1,557,489				5
Other debits (explain in footnotes)						6
Total Debits:	**3,816,294**	**1,557,489**	**0**	**0**	**0**	
Balance End of Year:	**3,260,019**	**1,155,119**	**0**	**0**	**0**	

Particulars (a)	Total Utility Customers (g)	Officers & Employees (h)	Other (i)	Total (j)	
Balance First of Year	**4,470,642**	0	186,955	4,657,597	1
Add: provision for uncollectibles during year					
Provision for uncollectibles during year	**4,277,397**		208,283	4,485,680 *	2
Collection of accts prev written off: Utility Customers	**1,040,882**		26,816	1,067,698	3
Other credits (explain in footnotes)	**0**			0	4
Total Credits:	**5,318,279**	**0**	**235,099**	**5,553,378**	
Less: Accounts written off					
Accounts written off during the year: Utility Customers	**5,373,783**		128,347	5,502,130	5
Other debits (explain in footnotes)	**0**			0	6
Total Debits:	**5,373,783**	**0**	**128,347**	**5,502,130**	
Balance End of Year:	**4,415,138**	**0**	**293,707**	**4,708,845**	
Loss on Wisconsin utility accounts					
Accounts written off	**0**			5,193,220	7
Collection of such accounts	**0**			1,005,907	8
Net Loss:				**4,187,313**	

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR (ACCT. 144)

Accumulated Provision for Uncollectible Accounts - CR (Acct. 144) (Page F-25)

General footnotes

Line 2 includes an accrual for $76,610 in which the offsetting transaction was not FERC Account 904.

NOTES RECEIVABLE FROM ASSOCIATED COMPANIES (ACCT. 145)

Name of Company (a)	Issue Date (b)	Maturity Date (c)	Interest Rate (d)	Amount End of Year (e)	
None					1
			Total:	0	

MATERIALS AND SUPPLIES (ACCTS. 151-157, 163)

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates for amounts by function are acceptable. In column (d), designate the departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating systems, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Account (a)	Balance First of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)	
Fuel Stock (Account 151)	13,164,689	13,385,917	Electric	1
Fuel Stock Expenses Undistributed (Account 152)	0	0		2
Residuals and Extracted Products (Account 153)	0	0		3
Plant Materials and Operating Supplies (Account 154)				4
Assigned to Construction (Estimated)	350,060	515,434	Electric & Gas	5
Assigned to Operations and Maintenance	0			6
Production Plant (Estimated)	1,895,417	1,883,712	Electric	7
Transmission Plant (Estimated)	1,563,580	1,722,707	Electric	8
Distribution Plant (Estimated)	939,082	923,006	Electric & Gas	9
Other Account 154 (specify):				
	(156,431)	(156,066)		* 10
	0			11
	0			12
	0			13
	0			14
Total Account 154:	**4,591,708**	**4,888,793**		
Merchandise (Account 155)	531	531	Electric	15
Other Materials and Supplies (Account 156)	0	0		16
Nuclear Materials Held for Sale (Account 157)	0	0		17
Stores Expense Undistributed (Account 163)	0	0		18
Total Materials and Supplies:	**17,756,928**	**18,275,241**		

MATERIALS AND SUPPLIES (ACCTS. 151-157, 163)

Materials and Supplies (Accts. 151-157, 163) (Page F-27)

General footnotes

Explain any non-zero amounts under "Assigned to - Other" line 10

Assigned to Other - Includes miscellaneous inventory items such as obsolescence, suspense items, purchase price variances and inventory held for sale.

ALLOWANCES (ACCOUNTS 158.1 AND 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 2 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 21-25.

Activity (a)	2009 No. (b)	2009 Amt. (c)	2010 No. (d)	2010 Amt. (e)	
Allowances Inventory (Account 158.1)					
Transactions:					
Balance-Beginning of Year	10,580		1,193		1
Acquired During Year:					
Issued (Less Withheld Allow)	520		493		2
Returned by EPA					3
Purchases/Transfers:					
	1,047	455,283			4
					5
					6
					7
					8
					9
Total	**1047**	**455283**	**0**	**0**	
Relinquished During Year:					
Charges to Account 509	1,447	452,293			10
Allowances Surrendered	739				11
Cost of Sales/Transfers:					
					12
					13
					14
					15
					16
					17
Total	**0**	**0**	**0**	**0**	
Balance-End of Year	**9961**	**2990**	**1686**	**0**	
Sales:					
Net Sales Proceeds (Assoc. Co.)					18
Net Sales Proceeds (Other)					19
Gains					20
Losses					21
Allowances Withheld (Account 158.2)					
Transactions:					
Balance-Beginning of Year	17		17		22
Add: Withheld by EPA					23
Deduct: Returned by EPA					24
Cost of Sales	17				25
Balance-End of Year	**0**	**0**	**17**	**0**	
Sales:					
Net Sales Proceeds (Assoc. Co.)					26
Net Sales Proceeds (Other)	17	1,186			27
Gains		1,186			28
Losses					29

ALLOWANCES (ACCOUNTS 158.1 AND 158.2) (cont.)

6. Report on Line 3 allowances returned by the EPA. Report on Line 25 the EPA's sales of the withheld allowances. Report on Lines 26-29 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 4-9 the names of the vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 12-17 the name of purchasers/transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 18-21 and 26-29 the net sales proceeds and gains or losses from allowance sales.

2011 No. (f)	2011 Amt. (g)	2012 No. (h)	2012 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	
1,193		1,193		31,018		**45177**	**0**	**1**
493		493		2,179		**4178**	**0**	**2**
						0	**0**	**3**
						1047	**455283**	**4**
						0	**0**	**5**
						0	**0**	**6**
						0	**0**	**7**
						0	**0**	**8**
						0	**0**	**9**
0	**0**	**0**	**0**	**0**	**0**	**1047**	**455283**	
						1447	**452293**	**10**
						739	**0**	**11**
						0	**0**	**12**
						0	**0**	**13**
						0	**0**	**14**
						0	**0**	**15**
						0	**0**	**16**
						0	**0**	**17**
0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
1686	**0**	**1686**	**0**	**33197**	**0**	**48216**	**2990**	
						0	**0**	**18**
						0	**0**	**19**
						0	**0**	**20**
						0	**0**	**21**
17		17		833		**901**	**0**	**22**
				34		**34**	**0**	**23**
						0	**0**	**24**
				17		**34**	**0**	**25**
17	**0**	**17**	**0**	**850**	**0**	**901**	**0**	
						0	**0**	**26**
				17	113	**34**	**1299**	**27**
					113	**0**	**1299**	**28**
						0	**0**	**29**

ALLOWANCES (ACCOUNTS 158.1 AND 158.2)

Allowances (Accounts 158.1 and 158.2) (Page F-28)

General footnotes

S02 Allowances Inventory (Account 158.1)

Balance-Beginning of Year:			
Current Year	10,580	$	0
2010	1,193	$	0
2011	1,193	$	0
2012	1,193	$	0
Future Years	31,018	$	0
Totals	45,177	$	0
Acquired During Year:			
Issued (Less Withheld Allow)			
Current Year	0	$	0
2010	0	$	0
2011	0	$	0
2012	0	$	0
Future Years	1,193	$	0
Totals	1,193	$	0
Purchases/Transfers:			
Current Year	0	$	0
2010	0	$	0
2011	0	$	0
2012	0	$	0
Future Years	0	$	0
Totals	0	$	0
Relinquished During Year:			
Charges to Account 509			
Current Year	0	$	0
2010	0	$	0
2011	0	$	0
2012	0	$	0
Future Years	0	$	0
Totals	0	$	0
Allowances Surrendered:			
Current Year	739	$	0
2010	0	$	0
2011	0	$	0
2012	0	$	0
Future Years	0	$	0
Totals	739	$	0
Balance-End of Year:			
Current Year	9,841	$	0
2010	1,193	$	0
2011	1,193	$	0
2012	1,193	$	0
Future Years	32,211	$	0
Totals	45,631	$	0

S02 Allowances Withheld (Account 158.2)

Balance-Beginning of Year:			
Current Year	17	$	0
2010	17	$	0
2011	17	$	0
2012	17	$	0
Future Years	833	$	0
Totals	901	$	0
Add: Withheld by EPA:			
Current Year	0	$	0
2010	0	$	0

ALLOWANCES (ACCOUNTS 158.1 AND 158.2) (cont.)

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ALLOWANCES (ACCOUNTS 158.1 AND 158.2)

2011	0	$ 0
2012	0	$ 0
Future Years	34	$ 0
Totals	34	$ 0
Cost of Sales:		
Current Year	17	$ 0
2010	0	$ 0
2011	0	$ 0
2012	0	$ 0
Future Years	17	$ 0
Totals	34	$ 0
Balance-End of Year:		
Current Year	0	$ 0
2010	17	$ 0
2011	17	$ 0
2012	17	$ 0
Future Years	850	$ 0
Totals	901	$ 0
Sales:		
Net Sales Proceeds (Other)		
Current Year	17	$ 1,186
2010	0	$ 0
2011	0	$ 0
2012	0	$ 0
Future Years	17	$ 113
Totals	34	$ 1,299

NOx Allowances Inventory (Account 158.1)

Balance-Beginning of Year:		
Current Year	0	$ 0
2010	0	$ 0
2011	0	$ 0
2012	0	$ 0
Future Years	0	$ 0
Totals	0	$ 0
Acquired During Year:		
Issued (Less Withheld Allow)		
Current Year	520	$ 0
2010	493	$ 0
2011	493	$ 0
2012	493	$ 0
Future Years	986	$ 0
Totals	2,985	$ 0
Purchases/Transfers:		
Current Year	1,047	$ 455,283
2010	0	$ 0
2011	0	$ 0
2012	0	$ 0
Future Years	0	$ 0
Totals	1,047	$ 455,283
Relinquished During Year:		
Charges to Account 509		
Current Year	1,447	$ 452,293
2010	0	$ 0
2011	0	$ 0
2012	0	$ 0
Future Years	0	$ 0
Totals	1,447	$ 452,293

Balance-End of Year:

ALLOWANCES (ACCOUNTS 158.1 AND 158.2) (cont.)

ALLOWANCES (ACCOUNTS 158.1 AND 158.2)

Current Year	120	$	2,990
2010	493	$	0
2011	493	$	0
2012	493	$	0
Future Years	986	$	0
Totals	2,585	$	2,990

ALLOWANCES (ACCOUNTS 158.1 AND 158.2) (cont.)

UNAMORTIZED DEBT DISCOUNT AND EXPENSE AND UNAMORTIZED PREMIUM ON DEBT (ACCTS. 181, 225, 226 AND 257)

1. Report below the particulars called for with respect to the unamortized debt discount and expense or net premium applicable to each class and series of long-term debt. Show separately any unamortized debt discount and expense or call premiums applicable to refunded issues. Show in column (a) the series, due date and method of amortization for each amount of debt discount and expense or premium. In column (b) show principal amount of debt on which the total discount and expense or premium, shown in column (c), was incurred.
2. Explain any charges or credits in column (f) and (g) other than amortization in Acct. 428 or 429.

Debt to Which Related (a)	Prin. Amt. of Debt to which Disc. and Exp. or Net Premiums Relate (b)	Total Discount and Expense or (net premiums) (c)	
Unamortized Debt Discount and Expense (181)			
First Mortgage Bonds Series Due Dec 01, 2026	65,000,000	493,150	1
First Mortgage Bonds Series Due Oct 01, 2018	150,000,000	1,422,896	2
First Mortgage Bonds Series Due Sept 01, 2038	200,000,000	2,100,071	3
Resource Recovery Financing Due Nov 01, 2021	18,600,000	192,829	4
Total (Acct. 181):	**433,600,000**	**4,208,946**	
Umamortized Premium on Long-Term Debt (225)			
NONE			5
Total (Acct. 225):	**0**	**0**	
Umamortized Discount on Long-Term Debt - Debit (226)			
First Mortgage Bonds Series Due Dec 01, 2026	65,000,000	268,450	6
First Mortgage Bonds Series Due Oct 01, 2018	150,000,000	861,000	7
First Mortgage Bonds Series Due Sept 01, 2038	200,000,000	1,530,000	8
Total (Acct. 226):	**415,000,000**	**2,659,450**	
Umamortized Gain on Reacquired Debt (257)			
NONE			9
Total (Acct. 257):	**0**	**0**	

UNAMORTIZED DEBT DISCOUNT AND EXPENSE AND UNAMORTIZED PREMIUM ON DEBT (ACCTS. 181, 225, 226 AND 257) (cont.)

Balance First of Year (d)	Account Charged or Credited (e)	Charges During Year (f)	Credits During Year (g)	Balance End of Year (h)	
293,959			293,959	**0**	**1**
923,959			94,732	**829,227**	**2**
2,079,734			71,123	**2,008,611**	**3**
70,169			5,464	**64,705**	**4**
3,367,821		**0**	**465,278**	**2,902,543**	
0				**0**	**5**
0		**0**	**0**	**0**	
160,270			160,270	**0**	**6**
559,443			57,359	**502,084**	**7**
1,514,208			51,009	**1,463,199**	**8**
2,233,921		**0**	**268,638**	**1,965,283**	
0				**0**	**9**
0		**0**	**0**	**0**	

OTHER REGULATORY ASSETS (ACCOUNT 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making process of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show the period of amortization in column (a).
3. Minor items (5% of the Balance End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Description and Purpose of Other Regulatory Assets (a)	Balance First of Year (b)	Debit Amount (c)	Credits Account Charged (d)	Credits Amount (e)	Balance End of Year (f)		
AFC in Excess of FERC-Carrying Chgs-Electric -Amortized over plant lives	2,845,525	148,303	405	159,980	**2,833,848**		1
AFC in Excess of FERC-Carrying Chgs-Gas -Amortized over plant lives	391,441	12,049	405	41,459	**362,031**		2
AFC in Excess of FERC-Carrying Chgs-Common -Amortized over plant lives	645,302	56,088	405	127,184	**574,206**		3
Net-of-Tax AFUDC Adjustments -Amortized over plant lives	8,618,671	593,351	282	68,716	**9,143,306**		4
Conservation Programs -Amortization amount per PSCW rate order 4220-UR-115	711,077	11,597,562	908	10,169,613	**2,139,026**		5
Environmental Cleanup - MGP Sites -Amortization amount per PSCW rate order 4220-UR-115	63,727,173	36,232,261	Various	4,905,878	**95,053,556**	*	6
Contract Valuation Adjustment	2,883,730		245.1	2,883,730	**0**		7
Michigan Restructuring - Deferral per MPSC letter dated April 30, 2001 Case No. U-12907	28,859				**28,859**		8
MISO Day 2 WI Retail Deferral -Amortization amount per PSCW rate order 4220-UR-115	3,041,268	229,417	557	3,270,685	**0**		9
Pension and Employee Benefit Obligations	86,595,188	8,522,431	Various	3,755,003	**91,362,616**	*	10
Asset Retirement Recovery	310,492	3,196			**313,688**		11
Nuclear Decommissioning Deferral -Amortization amount per PSCW rate order 4220-UR-115	8,775,519	446,131	557	2,928,734	**6,292,916**		12
FAS 109 Prior Flow Through	2,229,856	2,297,719	254	2,229,856	**2,297,719**		13
	0				**0**		14
	0				**0**		15
Total:	**180,804,101**	**60,138,508**		**30,540,838**	**210,401,771**		

OTHER REGULATORY ASSETS (ACCOUNT 182.3)

Other Regulatory Assets (Account 182.3) (Page F-32)

General footnotes

Environmental Cleanup MGP Sites
Accounts Charged:

143	$ 2,805,286
735	1,089,619
242	965,973
Total	$ 4,905,878

Pension and Employee Benefit Obligations
Accounts Charged:

184	$ 2,645,003
228.3	1,110,000
Total	$ 3,755,003

MISCELLANEOUS DEFERRED DEBITS (ACCT. 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show the period of amortization in column (a).
3. Minor items (5% of the Balance End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Description (a)	Balance First of Year (b)	Debit Amount (c)	Credits: Account Charged (d)	Credits: Amount (e)	Balance End of Year (f)		
L-T Income Tax and Int Rec	0	112,412			**112,412**		1
Contracts Receivable	2,642,268		Various	922,439	**1,719,829**	*	2
NSP-WI Wholesale Rate Case Costs (Docket ER06-1319-000)	162,805		928	139,547	**23,258**		3
	0				**0**		4
Total:	**2,805,073**	**112,412**		**1,061,986**	**1,855,499**		

MISCELLANEOUS DEFERRED DEBITS (ACCT. 186)

Miscellaneous Deferred Debits (Acct. 186) (Page F-33)

General footnotes

Contracts Receivable
Accounts Charged:

252	$760,714
419	161,725
Total	$922,439

RESEARCH AND DEVELOPMENT EXPENDITURES (ACCT. 188)

1. Explain below and show the cost incurred during the year for technological research and development projects including amounts paid to others during the year for jointly sponsored projects and other payments made as a result of the company's membership in trade or technical associationsand subscriptions or assessments for such projects.
2. Items under $5,000 incurred for similar projects may be grouped.
3. For any R&D work carried on by the company in which there is a sharing of costs with others, show separately the company's cost for the year and cost chargeable to others.

Description (a)	Balance First of Year (b)	Debit Amount (c)	Credits: Account Charged (d)	Credits: Amount (e)	Balance End of Year (f)		
Electric Power Research Institute:	0				**0**		**1**
Dues	0	53,693	various	53,693	**0**	*	**2**
Other	0	3,001	various	3,001	**0**	*	**3**
Edison Electric Institure:	0				**0**		**4**
Dues	0	165,209	various	165,209	**0**	*	**5**
Other	0	956	921	956	**0**		**6**
American Gas Association	0	22,788	930.2	22,788	**0**		**7**
American Wind Energy Association	0	2,850	930.2	2,850	**0**		**8**
Carbon Sequestration Council	0	1,680	930.2	1,680	**0**		**9**
Emerging Energy Research	0	1,123	921	1,123	**0**		**10**
Energy Insights	0	2,987	various	2,987	**0**	*	**11**
Environmental Systems Research	0	655	various	655	**0**	*	**12**
GKA Research	0	2,525	923	2,525	**0**		**13**
Midwest Research Institute		76,500	426.1	76,500	**0**		**14**
Mountain States Hydrogen Bus. Council		16	930.2	16	**0**		**15**
National Hydrogen Association		627	921	627	**0**		**16**
National Renewable Energy Laboratory		569	930.1	569	**0**		**17**
North American Transmission Forum		3,606	930.2	3,606	**0**		**18**
Nvision Research Inc		8,727	921	8,727	**0**		**19**
Sam Research AG		1,036	923	1,036	**0**		**20**
Sundel Research Inc.		80	921	80	**0**		**21**
University of North Dakota		10,000	930.2	10,000	**0**		**22**
Total:	**0**	**358,628**		**358,628**	**0**		

RESEARCH AND DEVELOPMENT EXPENDITURES (ACCT. 188)

Research and Development Expenditures (Acct. 188) (Page F-34)

General footnotes

Electric Power Research Institute Dues
Accounts Charged:

921	$ 16,583
923	6,711
930.2	30,399
Total	$ 53,693

Electric Power Research Institute Other
Accounts Charged:

580	$ 2,936
921	65
Total	$ 3,001

Edison Electric Institute Dues
Accounts Charged:

426.1	$ 1,899
426.4	14,061
930.2	149,249
Total	$165,209

Energy Insights
Accounts Charged:

908	$ 739
930.2	2,248
Total	$ 2,987

Environmental Systems Research
Accounts Charged:

561.2	$ 249
588	87
880	76
921	243
Total	$ 655

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, explain in footnote giving particulars (details) of the change. State the reason for any charge-off during the year and specify the amount charged.

Class and Series of Stock (a)	Balance End of Year (b)	
NONE		1
Total:	**0**	

ACCUMULATED DEFERRED INCOME TAXES (ACCT. 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify in Footnote), include deferrals relating to other income and deductions.

Description and Location (a)	Balance First of Year (b)	Balance End of Year (c)		
Electric				
	43,027,625	53,168,550	*	1
Total Electric:	**43,027,625**	**53,168,550**		
Gas				
	31,084,956	43,915,688	*	2
Total Gas:	**31,084,956**	**43,915,688**		
Water				
NONE	0			3
Total Water:	**0**	**0**		
Other (Specify in footnote)				
NONE	0			4
Total Other (Specify in footnote):	**0**	**0**		
Common				
NONE	0			5
Total Common:	**0**	**0**		
Non-Utility				
Non Operating	2,015,047	2,321,191	*	6
Total Non-Utility:	**2,015,047**	**2,321,191**		
Total Account 190:	**76,127,628**	**99,405,429**		

ACCUMULATED DEFERRED INCOME TAXES (ACCT. 190)

Accumulated Deferred Income Taxes (Acct. 190) (Page F-36)

General footnotes

	12/31/2008	12/31/2009
Electric (Other)		
Avoided Tax Interest	7,264,496	7,735,898
Bad Debts	1,654,109	1,627,279
CIAC - Connection Fees	10,613,141	11,905,122
Customer Adv - Construction	1,799,973	709,272
Deferred Compensation Plan Reserve	674,737	211,820
ESOP Dividends	489,975	524,966
Executive Incentive	74,087	0
Reg Diff - Effect of Rate Changes	1,498,924	1,530,387
Regulatory Difference - ITC Grossup	6,775,641	8,071,840
Fuel Tax Credit - Inc Addback	2,191	435
Hydropower Credit	0	93,159
ITC Grant	0	2,586,558
Inventory Reserve	60,489	59,852
Litigation Reserve	120,293	0
Medical Deductions - Self Insured	106,514	50,455
Non Qualified Pension Plans	0	377,401
Nuclear Refueling Outage Costs	1,914,848	326,226
Performance Share Plan	0	96,248
Post Empl Benefits - Retiree Medical	3,568,363	4,049,030
Post Empl Benefits - Workmen's Comp	531,427	253,792
Primary Fund Loss	426,171	414,695
Rate Refund Reserve	3,925,730	3,152,251
Regulatory Liability - MISO Day 2	0	68,267
Regulatory Liability - IRC Sec 199	386,660	515,863
Regulatory Liability - Refund Obligation	29,915	7,415,627
Regulatory Reserve	95,261	205,466
R & E Credit	0	167,697
Sale of Emission Allowances	133,575	73,550
Severance Accrual	160,205	184,480
Vacation Accrual	688,827	735,089
State Tax Deduction Cash Versus Accrual	32,073	25,825
Total	43,027,625	53,168,550
Gas (Other)		
Avoided Tax Interest	426,308	392,901
Bad Debts	213,480	260,954
CIAC - Connection Fees	1,032,554	1,009,426
Deferred Compensation Plan Reserve	126,994	42,009
Environmental Remediation	27,687,630	40,415,830
ESOP Dividends	251,159	278,215
Executive Incentive Plans	13,945	0
Regulatory Diff - Effect of Rate Chgs	136,314	158,227
Regulatory Difference - ITC Grossup	163,157	145,206
Inventory Reserve	7,036	6,761
Lower of Cost or Mkt on Gas Invent	19,898	0
Medical Deductions - Self Insured	20,047	10,006
Non Qualified Pension Plans	0	74,847
Performance Share Plan	0	19,088
Post Empl Benefits - Retiree Medical	671,612	803,012
Post Empl Benefits - Workmen's Comp	100,021	50,333
Primary Fund Loss	55,002	66,501
Severance Accrual	30,153	36,587
Vacation Accrual	129,646	145,785
Total	31,084,956	43,915,688
Nonutility		
Contributions Carryover	500,497	616,823
Federal Net Operating Loss	1,117,823	1,307,641
Michigan HB 5104	396,727	396,727
Total	2,015,047	2,321,191

ACCUMULATED DEFERRED INCOME TAXES (ACCT. 190)

CAPITAL STOCKS (ACCTS. 201 AND 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)	
Common Stock				
Common Stock	1,000,000	100.00	0	**1**
All NSP-Wisconsin Common Stock is owned by	0	0.00	0	**2**
its parent, Xcel Energy Inc.	0	0.00	0	**3**
	0	0.00	0	**4**
Total Common:	**1,000,000**			

CAPITAL STOCKS (ACCTS. 201 AND 204) (cont.)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year. Give particulars (detais) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

Outstanding per Balance Sheet (Total amount outstanding without reduction for amounts held by respondent)		Held by Respondent				
		As Reacquired Stock (Account 217)		In Sinking and Other Funds		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
933,000	93,300,000	0	0	0	0	1
0	0	0	0	0	0	2
0	0	0	0	0	0	3
0	0	0	0	0	0	4
933,000	**93,300,000**	**0**	**0**	**0**	**0**	

OTHER PAID-IN CAPITAL (ACCTS. 206-211, INCL.)

Report below the balance at the end of the year and the information specified below for the respective Other Paid-In-Capital accounts. Provide a subheading for each account and show a total for the account, as well as total for all accounts for reconciliation with Balance Sheet. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208): State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated Value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211): Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Item (a)	Amount (b)	
Account 211 - Miscellaneous Paid in Capital	0	1
Acquisition of Natural Gas, Inc. common stock (1998)	80,000	2
Contribution of capital by parent company (2001-2009)	113,086,938	3
TOTAL	113,166,938	4

LONG-TERM DEBT (ACCTS. 221-224, INCL.)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221 (Bonds), 222 (Reacquired Bonds), 223 (Advances from Associated Companies), and 224 (Other Long-Term Debt).
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column(a) the name of the court and date of court order under which such certificates were issued.
6. In column (b) show the interest or dividend rate of the debt issued.
7. In column (c) show the principal amount of bonds or other long-term debt originally issued.
8. In column (d) show the expense amount with respect to the amount of bonds or other long-term debt originally issued.
9. In column (e) show the premium amount with respect to the amount of bonds or other long-term debt originally issued.
10. In column (f) show the discount amount with respect to the amount of bonds or other long-term debt originally issued.
11. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Class and Series of Obligation, Coupon Rate (For new issue, give commission authorization numbers and dates) (a)	Interest or Dividend Rate (b)	Principal Amount of Debt Issued (c)		
Account 221				
Series: NONE				
First Mortgage Bonds	5.250000%	150,000,000		1
First Mortgage Bonds	6.375000%	200,000,000		2
First Mortgage Bonds	7.375000%	65,000,000	*	3
Subtotal NONE:		**415,000,000**		
Subtotal Account 221:		**415,000,000**		
Account 222				
Series: NONE				
				4
Subtotal NONE:		**0**		
Subtotal Account 222:		**0**		
Account 223				
Series: NONE				
NONE				5
Subtotal NONE:		**0**		
Subtotal Account 223:		**0**		
Account 224				
Series: NONE				
Resource Recovery Revenue Bonds	6.000000%	18,600,000		6
Fort McCoy System Acquisition	7.000000%	996,655	*	7
Subtotal NONE:		**19,596,655**		
Subtotal Account 224:		**19,596,655**		
Total:		**434,596,655**		

LONG-TERM DEBT (ACCTS. 221-224, INCL.) (cont.)

12. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
13. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
14. In a footnote, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during the year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
15. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
16. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
17. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (j). Explain in a footnote any difference between the total of column (j) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
18. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Total Expense Amount (d)	Total Premium Amount (e)	Total Discount Amount (f)	Nominal Date of Issue (g)	Date of Maturity (h)	Outstanding Amount (i)	Interest for Year Amount (j)		
1,422,896	0	861,000	10/02/2003	10/01/2018	150,000,000	8,001,953		1
2,100,071	0	1,530,000	09/10/2008	09/01/2038	200,000,000	12,750,000		2
493,150	0	268,450	12/12/1996	12/01/2026		798,958	*	3
4,016,117	**0**	**2,659,450**			**350,000,000**	**21,550,911**		
4,016,117	**0**	**2,659,450**			**350,000,000**	**21,550,911**		
								4
0	**0**	**0**			**0**	**0**		
0	**0**	**0**			**0**	**0**		
								5
0	**0**	**0**			**0**	**0**		
0	**0**	**0**			**0**	**0**		
192,829	0	0	11/01/1996	11/01/2021	18,600,000	1,116,000		6
	0	0	10/15/2000	10/15/2030	692,590	50,353	*	7
192,829	**0**	**0**			**19,292,590**	**1,166,353**		
192,829	**0**	**0**			**19,292,590**	**1,166,353**		
4,208,946	**0**	**2,659,450**			**369,292,590**	**22,717,264**		

LONG-TERM DEBT (ACCTS. 221-224, INCL.)

Long-Term Debt (Accts. 221-224, incl.) (Page F-40)

General footnotes

Instruction 11

In March 2009, NSP-Wisconsin redeemed its 7.375 percent $65.0 million First Mortgage Bonds due December 1, 2026. The unamortized debt expense and unamortized debt discount at the time of redemption were transferred to an unamortized loss on reacquired debt account.

Instruction 14

Details for Account 224 of Net Changes during the Year

	Balance 12/31/08	Additions	Reductions	Balance 12/31/09
Fort McCoy System Acquisition	$ 726		(33)	$ 693
Resource Recovery Revenue Bonds	$ 18,600			$ 18,600
Total	$ 19,326			$ 19,293

LONG-TERM DEBT (ACCTS. 221-224, INCL.) (cont.)

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NOTES PAYABLE (ACCT. 231)

1. Report each issue separately.
2. If there is more than one interest rate for an aggregate obligation issue, average the interest rates and report one rate.

Name of Payee and Purpose for which Issued (a)	Date of Note (b)	Date of Maturity (c)	Interest Rate (d)	Balance End of Year (e)	
NONE					1
			Total:	**0**	

NOTES PAYABLE TO ASSOCIATED COMPANIES (ACCT. 233)

Name of Company (a)	Issue Date (b)	Maturity Date (c)	Interest Rate (d)	Amount End of Year (e)	
NSP-MN Intercompany borrowing agreement	01/01/2009		0.000%	15,500,000	* 1
			Total:	**15,500,000**	

NOTES PAYABLE TO ASSOCIATED COMPANIES (ACCT. 233)

Notes Payable to Associated Companies (Acct. 233) (Page F-43)

General footnotes

NSP-Wisconsin has an intercompany borrowing arrangement with NSP-Minnesota, with interest charged at NSP-Minnesota's short-term rate, which is variable.

TAXES ACCRUED (ACCT. 236)

1. The balance of accruals for income taxes should be classified by the years to which the tax is applicable.
2. The balance of any accruals materially in excess of the liability admitted by the tax returns of the utility shall be transferred from this account and reported in an appropriately designated reserve account.

Kind of Tax (a)	Balance First of Year (b)	Amounts Accrued (c)	Payments During Year (d)	Other Items cr. or (dr.) (e)	Balance End of Year (f)		
FEDERAL Income	5,624,714	16,708,272	25,877,150	3,544,164	**0**	*	1
Unemployment-2008	464		464		**0**		2
Unemployment-2009	0	35,893	35,313		**580**		3
FICA-2008	13,585		13,585		**0**		4
FICA-2009	0	3,610,117	3,401,296	34,960	**243,781**	*	5
	0				**0**		6
WISCONSIN Income	1,706,562	1,229,296	4,157,763	1,221,905	**0**	*	7
Unemployment-2008	2,988		2,988		**0**		8
Unemployment-2009	0	215,457	212,000	(140)	**3,317**	*	9
Real-Estate-2008	120,072		120,340	268	**0**	*	10
Real-Estate-2009	0	120,268		(268)	**120,000**	*	11
Use-2008	287,726		287,726		**0**		12
Use-2009	0	1,865,460	1,677,265		**188,195**		13
	0				**0**		14
MICHIGAN Income	129,014	(15,247)	10,752	465	**103,480**	*	15
Unemployment-2008	0				**0**		16
Unemployment-2009	0	4,874	4,874		**0**		17
Real-Estate-2008	22,498		22,498		**0**		18
Real-Estate-2009		132,974	108,944		**24,030**		19
Personal Property-2008	72,667		72,667		**0**		20
Personal Property-2009		509,174	445,022	14,222	**78,374**	*	21
Use-2008	(849)			849	**0**	*	22
Use-2009		11,976	11,294	(849)	**(167)**	*	23
	0				**0**		24
Xcel Services Misc. alloc.	0	106,508	106,508		**0**		25
	0				**0**		26
Total:	**7,979,441**	**24,535,022**	**36,568,449**	**4,815,576**	**761,590**		

TAXES ACCRUED (ACCT. 236)

Taxes Accrued (Acct. 236) (Page F-44)

General footnotes

1.	Federal income tax expense (409.1 & 409.2)	
	accrued as long-term income tax receivable (186)	89,426
	ITC Grant Deferral Accrued to 253	(2,586,558)
	Adjustment for debit balance reclass	6,037,279
	Federal income tax expense (409.1 & 409.2)	
	accrued liability for uncertain tax positions (242)	8,720
	Federal income tax expense (409.1 & 409.2)	
	accrued liability for uncertain tax positions (253)	(4,703)
	Total	3,544,164
5.	2009 balance sheet adjustment	34,960
7.	State income tax expense (409.1 & 409.2) accrued	
	as long-term income tax receivable (186)	19,582
	Rounding	1
	State income tax expense (409.1 & 409.2) accrued	
	liability for uncertain tax positions (242)	(66,137)
	State income tax expense (409.1 & 409.2 accrued	
	liability for uncertain tax positions (253)	83,590
	Adjustment for debit balance reclass	1,184,869
	Total	1,221,905
9.	2009 balance sheet adjustment	(141)
	Rounding	1
	Total	(140)
10.	Adjustment for payment of 2008 taxes in 2009 over	
	amount accrued in 2008	268
11.	Adjustment for payment of 2008 taxes in 2009 over	
	amount accrued in 2008	(268)
15.	State income tax expense (409.1 & 409.2) accrued	
	as long-term income tax receivable (186)	465
21.	Refund of prior year payment	14,222
22.	Adjustment for debit balance 2008	849
23.	Adjustment for debit balance 2008	(849)

OTHER DEFERRED CREDITS (ACCOUNT 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Description (a)	Balance First of Year (b)	Debits: Contra Account (c)	Debits: Amount (d)	Credit Amount (e)	Balance End of Year (f)		
Deferred Comp Liability	376,439	131	61,894	42,277	**356,822**		1
Deferred Comp Wealth Option	321,874	232	73,494	27,793	**276,173**		2
Environmental Cleanup Liability	68,017,560	Various	5,836,625	32,903,720	**95,084,655**	*	3
Red Cedar River Enhancement Fund	74,063	146	23,043	6,906	**57,926**		4
Executive PSP - Long Term	97,695	232	56,048	115,199	**156,846**		5
Long Term Income Tax & Interest Payable	296,891	Various	422,247	261,728	**136,372**	*	6
Customer Prepayments	69,353	186	69,353		**0**		7
Pre-Funded AFUDC FERC Transmission	4,228	405	127	50,533	**54,634**	*	8
L-T Payroll Tax Liability				34,387	**34,387**		9
Deferred Revenue - ITC Grant				2,542,419	**2,542,419**		10
Total:	**69,258,103**		**6,542,831**	**35,984,962**	**98,700,234**		

OTHER DEFERRED CREDITS (ACCOUNT 253)

Other Deferred Credits (Account 253) (Page F-45)

General footnotes

Environmental Cleanup Liability
Accounts Charged:

242	$ 5,818,858
182.3	13,687
566	4,080
Total	$ 5,836,625

Long Term Income Tax and Interest Payable
Accounts Charged:

232	$ 196,608
282	79,250
431	78,615
419	67,774
Total	$ 422,247

Pre-Funded AFUDC FERC Transmission:
The amount reported in column d for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midwest ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company (unjurisdictionalized) amount is provided below:

	Total
Pre-funded AFUDC-FERC Transmission	$9,944

The amount reported in column e for Pre-funded AFUDC-FERC Transmission is a jurisdictional amount. For purposes of calculating the Midwest ISO Formula Rate under Attachment O of the Northern States Power Companies FERC Tariff, a total company (unjurisdictionalized) amount is provided below:

	Total
Pre-funded AFUDC-FERC Transmission	$3,956,000

OTHER REGULATORY LIABILITIES (ACCOUNT 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance End of Year for Account 254 or amounts less than $50,000, whichever is less) may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Description (a)	Balance First of Year (b)	Debits: Account Charged (c)	Debits: Amount (d)	Credit Amount (e)	Balance End of Year (f)	
ITC Gross Up	6,938,799			1,278,278	**8,217,077**	**1**
Deferred Electric Fuel Cost - Michigan PSCR	0				**0**	**2**
- Amortized over 12 month period	237,571	557	301,427	576,244	**512,388**	**3**
Emission Allowances	0				**0**	**4**
- Amortized per PSCW rate order 4220-UR-115	333,123	411.8	161,322	11,615	**183,416**	**5**
Purchased Gas Over/Under Recovery	0				**0**	**6**
- Generally amortized over 12 month period	1,140,258	805.1	7,012,501	6,174,265	**302,022**	**7**
IRC Section 199 Credit	964,293	407.4	168,658	490,814	**1,286,449**	**8**
- Amortized per PSCW rate order 4220-UR-115	0				**0**	**9**
WI Retail Fuel Refund	74,605	557	74,605		**0**	**10**
- Amortized per PSCW rate order 4220-UR-115	0				**0**	**11**
WI Retail Fuel Refund				18,492,975	**18,492,975**	**12**
MISO Day 2 Retail Deferral				170,243	**170,243**	**13**
Derivatives and Hedging - Retail Gas				593,150	**593,150**	**14**
Total:	**9,688,649**		**7,718,513**	**27,787,584**	**29,757,720**	

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ACCT. 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (h) the average period over which tax credits are amortized.

Account Subdivisions (a)	Balance First of Year (b)	Deferred for Year Acct. No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Acct. No. (e)	Allocations to Current Year's Income Amount (f)		
Electric							
4%	14,517				3,744		1
10%	9,992,516				595,302		2
Total Electric:	**10,007,033**		**0**		**599,046**		
Gas							
3%	0						3
4%	22				19		4
7%	0						5
10%	229,747				26,077		6
Total Gas:	**229,769**		**0**		**26,096**		
Water							
3%	0						7
4%	0						8
7%	0						9
10%	0						10
Total Water:	**0**		**0**		**0**		
Common							
3%	0						11
4%	0						12
7%	0						13
10%	129,129				8,714	*	14
Total Common:	**129,129**		**0**		**8,714**		
Nonutility							
3%	0						15
4%	0						16
7%	0						17
10%	0						18
Total Nonutility:	**0**		**0**		**0**		
Other (Specify in Footnote)							
3%	0						19
4%	0						20
7%	0						21
10%	0						22
Total Other (Specify in Footnote):	**0**		**0**		**0**		
Total	**10,365,931**		**0**		**633,856**		

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ACCT. 255) (cont.)

Adjustments (g)	Balance End of Year (h)	Average Period of Allocation to Income (i)	Adjustment Explanation (j)	
	10,773			1
	9,397,214			2
0	9,407,987			
	0			3
	3			4
	0			5
	203,670			6
0	203,673			
	0			7
	0			8
	0			9
	0			10
0	0			
	0			11
	0			12
	0			13
	120,415			* 14
0	120,415			
	0			15
	0			16
	0			17
	0			18
0	0			
	0			19
	0			20
	0			21
	0			22
0	0			
0	9,732,075			

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ACCT. 255)

Accumulated Deferred Investment Tax Credits (Acct. 255) (Page F-47)

General footnotes

14. Common Allocation

Electric - 89.01%	107,181
Gas - 10.99%	13,234
Total	120,415

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (ACCT. 255) (cont.)

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ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (ACCT. 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.
2. For Other (Specify in Footnote), include deferrals relating to other income and deductions.

Particulars (a)	Balance First of Year (b)	Changes During Year: Amounts Debited to Acct. 410.1 (c)	Changes During Year: Amounts Credited to Acct. 411.1 (d)	Changes During Year: Amounts Debited to Acct. 410.2 (e)	Changes During Year: Amounts Credited to Acct. 411.2 (f)	
Account 281						
Electric						
Pollution Control Facilties	0	450,866				1
Total Electric:	**0**	**450,866**	**0**	**0**	**0**	
Gas						
NONE	0					2
Total Gas:	**0**	**0**	**0**	**0**	**0**	
Water						
NONE	0					3
Total Water:	**0**	**0**	**0**	**0**	**0**	
Steam						
NONE	0					4
Total Steam:	**0**	**0**	**0**	**0**	**0**	
Common						
NONE	0					5
Total Common:	**0**	**0**	**0**	**0**	**0**	
Non-Utility						
NONE	0					6
Total Non-Utility:	**0**	**0**	**0**	**0**	**0**	
Other (Specify in Footnote)						
NONE	0					7
Total Other (Specify in Footnote):	**0**	**0**	**0**	**0**	**0**	
Total Account 281:	**0**	**450,866**	**0**	**0**	**0**	
Classification of Total						
Federal Income Tax	0	423,724				8
State Income Tax	0	27,142				9
Local Income Tax	0					10
Total:	**0**	**450,866**	**0**	**0**	**0**	

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (ACCT. 281) (cont.)

Adjustments					
Debits		Credits			
Account Charged (g)	Amount (h)	Account Charged (i)	Amount (j)	Balance End of Year (k)	
		281	2	**450,868**	**1**
	0		**2**	**450,868**	
				0	**2**
	0		**0**	**0**	
				0	**3**
	0		**0**	**0**	
				0	**4**
	0		**0**	**0**	
				0	**5**
	0		**0**	**0**	
				0	**6**
	0		**0**	**0**	
				0	**7**
	0		**0**	**0**	
	0		**2**	**450,868**	
			1	**423,725**	**8**
			1	**27,143**	**9**
				0	**10**
	0		**2**	**450,868**	

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (ACCT. 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. For Other (Specify in Footnote), include deferrals relating to other income and deductions.

Particulars (a)	Balance First of Year (b)	Changes During Year: Amounts Debited to Acct. 410.1 (c)	Amounts Credited to Acct. 411.1 (d)	Amounts Debited to Acct. 410.2 (e)	Amounts Credited to Acct. 411.2 (f)	
Account 282						
Electric						
	170,394,787	12,955,956				1
Total Electric:	**170,394,787**	**12,955,956**	**0**	**0**	**0**	
Gas						
	12,384,858	3,307,596				2
Total Gas:	**12,384,858**	**3,307,596**	**0**	**0**	**0**	
Water						
NONE	0					3
Total Water:	**0**	**0**	**0**	**0**	**0**	
Steam						
NONE	0					4
Total Steam:	**0**	**0**	**0**	**0**	**0**	
Common						
NONE	0					5
Total Common:	**0**	**0**	**0**	**0**	**0**	
Non-Utility						
Non Operating	(17,189)			603		6
Total Non-Utility:	**(17,189)**	**0**	**0**	**603**	**0**	
Other (Specify in Footnote)						
NONE	0					7
Total Other (Specify in Footnote):	**0**	**0**	**0**	**0**	**0**	
Total Account 282:	**182,762,456**	**16,263,552**	**0**	**603**	**0**	
Classification of Total						
Federal Income Tax	150,272,332	14,975,704		484		8
State Income Tax	32,490,124	1,287,848		119		9
Local Income Tax	0					10
Total:	**182,762,456**	**16,263,552**	**0**	**603**	**0**	

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (ACCT. 282) (cont.)

	Adjustments					
	Debits		Credits			
	Account Charged (g)	Amount (h)	Account Charged (i)	Amount (j)	Balance End of Year (k)	
	182.3,254, 410.2	1,182,430	182.3,254 & 282	2,075,144	**184,243,457**	**1**
		1,182,430		**2,075,144**	**184,243,457**	
	182.3,254 & 282	317,986	182.3 & 254	70,968	**15,445,436**	**2**
		317,986		**70,968**	**15,445,436**	
					0	**3**
		0		**0**	**0**	
					0	**4**
		0		**0**	**0**	
					0	**5**
		0		**0**	**0**	
			410.1	150	**(16,436)**	**6**
		0		**150**	**(16,436)**	
					0	**7**
		0		**0**	**0**	
		1,500,416		**2,146,262**	**199,672,457**	
		1,101,317		1,562,975	**165,710,178**	**8**
		399,099		583,287	**33,962,279**	**9**
					0	**10**
		1,500,416		**2,146,262**	**199,672,457**	

ACCUMULATED DEFERRED INCOME TAXES - OTHER (ACCT. 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For Other (Specify in Footnote), include deferrals relating to other income and deductions.

Particulars (a)	Balance First of Year (b)	Changes During Year: Amounts Debited to Acct. 410.1 (c)	Amounts Credited to Acct. 411.1 (d)	Amounts Debited to Acct. 410.2 (e)	Amounts Credited to Acct. 411.2 (f)	
Account 283						
Electric						
	36,624,170	7,130,398	6,895,387			1
Total Electric:	**36,624,170**	**7,130,398**	**6,895,387**	**0**	**0**	
Gas						
	31,325,191	16,162,209	2,810,667			2
Total Gas:	**31,325,191**	**16,162,209**	**2,810,667**	**0**	**0**	
Water						
NONE	0					3
Total Water:	**0**	**0**	**0**	**0**	**0**	
Steam						
NONE	0					4
Total Steam:	**0**	**0**	**0**	**0**	**0**	
Common						
NONE	0					5
Total Common:	**0**	**0**	**0**	**0**	**0**	
Non-Utility						
Non Operating	(496,499)					6
Total Non-Utility:	**(496,499)**	**0**	**0**	**0**	**0**	
Other (Specify in Footnote)						
NONE	0					7
Total Other (Specify in Footnote):	**0**	**0**	**0**	**0**	**0**	
Total Account 283:	**67,452,862**	**23,292,607**	**9,706,054**	**0**	**0**	
Classification of Total						
Federal Income Tax	54,166,029	18,942,078	7,802,425			8
State Income Tax	13,286,833	4,350,529	1,903,629			9
Local Income Tax	0					10
Total:	**67,452,862**	**23,292,607**	**9,706,054**	**0**	**0**	

ACCUMULATED DEFERRED INCOME TAXES - OTHER (ACCT. 283) (cont.)

	Adjustments – Debits – Account Charged (g)	Adjustments – Debits – Amount (h)	Adjustments – Credits – Account Charged (i)	Adjustments – Credits – Amount (j)	Balance End of Year (k)	
			283	18,433	**36,877,614**	**1**
		0		**18,433**	**36,877,614**	
	283	18,433			**44,658,300**	**2**
		18,433		**0**	**44,658,300**	
					0	**3**
		0		**0**	**0**	
					0	**4**
		0		**0**	**0**	
					0	**5**
		0		**0**	**0**	
			219	50,883	**(445,616)**	**6**
		0		**50,883**	**(445,616)**	
					0	**7**
		0		**0**	**0**	
		18,433		**69,316**	**81,090,298**	
		14,768		55,729	**65,346,643**	**8**
		3,665		13,587	**15,743,655**	**9**
					0	**10**
		18,433		**69,316**	**81,090,298**	

DETAIL OF OTHER BALANCE SHEET ACCOUNTS

Report each item (when individually or when like items are combined) greater than $100,000 and all lesser amounts grouped as Miscellaneous. Describe fully using other than account titles.

Particulars (a)	Balance End of Year (b)	Balance First of Year (c)	
Cash (131):			
NONE	0	0	1
Total (Acct. 131):	**0**	**0**	
Interest Special Deposits (132):			
NONE	0	0	2
Total (Acct. 132):	**0**	**0**	
Dividend Special Deposits (133):			
NONE	0	0	3
Total (Acct. 133):	**0**	**0**	
Other Special Deposits (134):			
ATC SALVAGE PAYMENT	393,548	393,040	4
Total (Acct. 134):	**393,548**	**393,040**	
Working Funds (135):			
CASH AGENTS / EMPLOYEE WORKING FUND	99,900	99,900	5
Total (Acct. 135):	**99,900**	**99,900**	
Temporary Cash Investments (136):			
WELLS FARGO SWEEP INVESTMENT ACCOUNT	228,929	30,889,073	6
Total (Acct. 136):	**228,929**	**30,889,073**	
Notes Receivable (141):			
NONE	0	0	7
Total (Acct. 141):	**0**	**0**	
Accounts Receivable from Associated Companies (146):			
XCEL VENTURES	31	0	8
CLEARWATER INVESTMENTS, INC.	545	876	9
NSP LANDS, INC.	2	36	10
CHIPPEWA & FLAMBEAU IMPROVEMENT COMPANY	878	0	11
XCEL ENERGY INC.	20,447,820	598,909	12
Total (Acct. 146):	**20,449,276**	**599,821**	
Fuel Stock (151):			
OIL INVENTORY	9,587,008	10,839,535	13
FUEL IN TRANSIT (COAL)	2,623,845	1,341,438	14
COAL INVENTORY	1,039,140	836,670	15
WOOD WASTE INVENTORY	133,236	141,859	16
MISCELLANEOUS	2,688	5,187	17
Total (Acct. 151):	**13,385,917**	**13,164,689**	

DETAIL OF OTHER BALANCE SHEET ACCOUNTS

Report each item (when individually or when like items are combined) greater than $100,000 and all lesser amounts grouped as Miscellaneous. Describe fully using other than account titles.

Particulars (a)	Balance End of Year (b)	Balance First of Year (c)	
Fuel Stock Expenses Undistributed (152):			
NONE	0	0	18
Total (Acct. 152):	**0**	**0**	
Residuals (153):			
NONE	0	0	19
Total (Acct. 153):	**0**	**0**	
Merchandise (155):			
MISCELLANEOUS	531	531	20
Total (Acct. 155):	**531**	**531**	
Other Materials and Supplies (156):			
NONE	0	0	21
Total (Acct. 156):	**0**	**0**	
Nuclear Materials Held for Sale (157):			
NONE	0	0	22
Total (Acct. 157):	**0**	**0**	
Allowances (Noncurrent Portion of Allowances) (158):			
NOX ALLOWANCES INVENTORY	2,990	0	23
Total (Acct. 158):	**2,990**	**0**	
Stores Expense Undistributed (163):			
NONE	0	0	24
Total (Acct. 163):	**0**	**0**	
Gas Stored Underground-Current (164.1):			
COMMODITY INJECTION FEES	137,613	105,361	25
COMMODITY COSTS TRANSFERED TO STORAGE	31,400,825	44,007,658	26
TRANSMISSION EXPENSE TRANSFERED TO STORAGE	1,008,224	1,202,167	27
STORED GAS WITHDRAWN FOR SYSTEM	(23,241,273)	(24,689,215)	28
Total (Acct. 164.1):	**9,305,389**	**20,625,971**	
LNG Stored (164.2):			
LNG STORED	860,080	1,093,974	29
Total (Acct. 164.2):	**860,080**	**1,093,974**	
Held for Processing (164.3):			
NONE	0	0	30
Total (Acct. 164.3):	**0**	**0**	
Prepayments (165):			
GROSS RECEIPTS TAX	19,387,403	18,377,329	31
INSURANCE	3,002,373	1,911,802	32
FEDERAL INCOME TAX PREPAYMENT	6,037,279	0	33

DETAIL OF OTHER BALANCE SHEET ACCOUNTS

Report each item (when individually or when like items are combined) greater than $100,000 and all lesser amounts grouped as Miscellaneous. Describe fully using other than account titles.

Particulars (a)	Balance End of Year (b)	Balance First of Year (c)	
Prepayments (165):			
WISCONSIN INCOME TAX PREPAYMENT	1,184,869	0	**34**
VEBA TRUST	80,987	245,902	**35**
AUTO LICENSING	94,145	147,922	**36**
WISCONSIN REMAINDER ASSESSMENT	354,480	327,245	**37**
NATURAL GAS IMBALANCE	(133,048)	8,965	**38**
MISCELLANEOUS	34,069	41,074	**39**
Total (Acct. 165):	**30,042,557**	**21,060,239**	
Advances for Gas (166-167):			
NONE	0	0	**40**
Total (Acct. 166-167):	**0**	**0**	
Interest and Dividends Receivable (171):			
INCOME TAX AUDIT INTEREST RECEIVABLE	78,728	0	**41**
Total (Acct. 171):	**78,728**	**0**	
Rents Receivable (172):			
POLE ATTACHMENTS	0	22,755	**42**
Total (Acct. 172):	**0**	**22,755**	
Accrued Utility Revenues (173):			
ELECTRIC RETAIL	31,004,563	21,632,428	**43**
ELECTRIC WHOLESALE	2,568,164	2,584,076	**44**
GAS	11,334,711	18,422,881	**45**
Total (Acct. 173):	**44,907,438**	**42,639,385**	
Miscellaneous Current and Accrued Assets (174):			
CLASSIFIED TEMPORARY INVESTMENT	2,039,815	7,271,365	**46**
Total (Acct. 174):	**2,039,815**	**7,271,365**	
Capital Stock Expense (214):			
NONE	0	0	**47**
Total (Acct. 214):	**0**	**0**	
Accounts Payable to Associated Companies (234):			
NORTHERN STATES POWER COMPANY MINNESOTA	31,242,763	12,415,640	**48**
XCEL ENERGY SERVICES	7,411,854	5,048,563	**49**
MISCELLANEOUS	59,432	136,194	**50**
Total (Acct. 234):	**38,714,049**	**17,600,397**	
Customer Deposits (235):			
DEPOSITS OF CUSTOMERS ACCOUNTS	1,999,221	1,930,030	**51**
Total (Acct. 235):	**1,999,221**	**1,930,030**	

DETAIL OF OTHER BALANCE SHEET ACCOUNTS

Report each item (when individually or when like items are combined) greater than $100,000 and all lesser amounts grouped as Miscellaneous. Describe fully using other than account titles.

Particulars (a)	Balance End of Year (b)	Balance First of Year (c)	
Interest Accrued (237):			
FIRST MORTGAGE BONDS 7.375% DUE 12-01-2026	0	399,479	**52**
FIRST MORTGAGE BONDS 5.25% DUE 10-01-2018	1,968,750	1,968,750	**53**
FIRST MORTGAGE BONDS 6.375% DUE 9-1-2038	4,250,000	3,931,250	**54**
RESOURCE RECOVERY REVENUE BONDS 6% DUE 11-01-2021	186,000	186,000	**55**
MISCELLANEOUS	10,100	15,393	**56**
Total (Acct. 237):	**6,414,850**	**6,500,872**	
Dividends Declared (238):			
XCEL ENERGY INC.	8,522,302	8,582,690	**57**
Total (Acct. 238):	**8,522,302**	**8,582,690**	
Matured Long-Term Debt (239):			
NONE	0	0	**58**
Total (Acct. 239):	**0**	**0**	
Matured Interest (240):			
NONE	0	0	**59**
Total (Acct. 240):	**0**	**0**	
Tax Collections Payable (241):			
SALES TAX	881,462	1,111,185	**60**
PAYROLL WITHHOLDING TAXES	520,882	141,673	**61**
Total (Acct. 241):	**1,402,344**	**1,252,858**	
Miscellaneous Current and Accrued Liabilities (242):			
ENVIRONMENTAL CLEAN-UP	5,703,704	1,032,324	**62**
RETIREE MEDICAL LIABILITY	737,000	0	**63**
RATE REFUND RESERVE-ELECTRIC	212,561	0	**64**
MISCELLANEOUS	139,000	114,521	**65**
NUCLEAR OUTAGE ACCOUNTING CHANGE	813,536	4,775,455	**66**
Total (Acct. 242):	**7,605,801**	**5,922,300**	

DISTRIBUTION OF TAXES TO ACCOUNTS

1. Explain basis for allocation if used.
2. If the total does not equal taxes accrued, include a reconciling footnote.

Function (a)	Wisconsin License Fee (b)	Wisconsin Income Tax (c)	Federal Income Tax (d)	FICA and Fed. & State Unemployment Tax (e)		
Accts. 408.1 and 409.1:						
Accts. 408.1 and 409.1: Electric	16,769,414	5,034,767	16,385,021	3,219,138		1
Accts. 408.1 and 409.1: Gas	1,689,819	308,017	(1,105,634)	637,272		2
Accts. 408.1 and 409.1: Water						3
Accts. 408.1 and 409.1: Steam						4
Accts. 408.2 and 409.2		(4,113,488)	1,428,885	9,931		5
Acct. 409.3						6
Clearing Accounts					*	7
Construction						8
Other (specify): None						9
Total:	**18,459,233**	**1,229,296**	**16,708,272**	**3,866,341**		

DISTRIBUTION OF TAXES TO ACCOUNTS (cont.)

PSC Remainder Assessment (f)	Local Property Tax (g)	State and Local Taxes Other Than Wisconsin (h)	Other Taxes (i)	Total (j)		
	3,000	654,638		**42,065,978**		1
		165,305		**1,694,779**		2
				0		3
				0		4
	117,268	(86,931)		**(2,644,335)**		5
				0		6
			1,877,436	**1,877,436**	*	7
				0		8
				0		9
0	**120,268**	**733,012**	**1,877,436**	**42,993,858**		

DISTRIBUTION OF TAXES TO ACCOUNTS

Distribution of Taxes to Accounts (Page F-56)

General footnotes

7. column (i)	Wisconsin use tax	1,865,460
	Michigan use tax	11,976
	Total	1,877,436

DISTRIBUTION OF TAXES TO ACCOUNTS (cont.)

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INTEREST AND DIVIDEND INCOME (ACCT. 419)

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	Interest or Dividend Rate (b)	Amount (c)	
Interest and Dividend Income (419):			
Revenues:			
CARRYING CHARGE ON NUCLEAR DECOMMISSIONING	5.400000%	446,131	1
INTEREST ON TEMPORARY CASH INVESTMENTS	Various	52,347	2
CARRYING CHARGE ON DEFERRED MISO DAY 2 COSTS	5.400000%	59,174	3
ECONOMIC DEVELOPMENT INVESTMENT LA CROSSE INDUSTRIAL PARK	Various	26,100	4
ECONOMIC DEVELOPMENT INVESTMENT GATEWAY INDUSTRIAL PARK	3.250000%	39,875	5
ECONOMIC DEVELOPMENT INVESTMENT CLEARWATER INDUSTRIAL PARK	3.250000%	58,221	6
INCOME TAX AUDIT AND UNCERTAIN TAX POSITIONS	Various	158,098	7
DEFERRED COMPENSATION LOSSES	Various	41,586	8
MISCELLANEOUS	Various	(3,884)	9
	Subtotal Revenues:	**877,648**	
Expenses:			
NONE			10
	Subtotal Expenses:	**0**	
Total (Acct. 419):		**877,648**	

INTEREST CHARGES (ACCTS. 427, 430 AND 431)

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	This Year Amount (b)	Last Year Amount (c)	
Interest on Long-Term Debt (427):			
FIRST MORTGAGE BONDS, 7.375%	798,958	4,793,750	1
FIRST MORTGAGE BONDS, 5.25%	8,001,953	8,002,301	2
FIRST MORTGAGE BONDS 6.375%	12,750,000	3,931,250	3
SENIOR NOTES, 7.64%		4,584,000	4
RESOURCE RECOVERY REVENUE BONDS, 6%	1,116,000	1,116,000	5
FORT MCCOY SYSTEM ACQUISITION, 7%	50,353	52,521	6
Total (Acct. 427):	**22,717,264**	**22,479,822**	
Interest on Debt to Assoc. Companies (430):			
NORTHERN STATES POWER COMPANY MINNESOTA, VARIABLE RATE	5,628	918,281	7
XCEL ENERGY SERVICES, VARIABLE RATE	53,566	121,262	8
Total (Acct. 430):	**59,194**	**1,039,543**	
Other Interest Expense (431):			
INTEREST ON WISCONSIN RETAIL RATE REFUNDS	756,667	325,949	9
INTEREST ON SETTLEMENT	(223,567)	44,623	10
MICHIGAN GCR INTEREST	8,360	8,762	11
MICHIGAN PSCR INTEREST	60,949	21,352	12
CREDIT FACILITIES FEES	60,833	50,941	13
CUSTOMER DEPOSIT INTEREST	34,247	38,002	14
REVERSAL OF INTEREST ACCRUED IN 2008 RELATED TO OVERCOLLECTED MGP CLE	(93,667)	93,667	15
DECOMMISSIONING PROVISION REFUND INTEREST	92,664		16
INTEREST ON DOMESTIC PRODUCTION TAX DEDUCTION (SEC. 199)	55,844	44,152	17
INCOME TAX AUDIT-FIN 48 INTEREST	(300)	78,338	18
SALES TAX AUDIT SETTLEMENT INTEREST	56,295	0	19
MISCELLANEOUS	3,655	242	20
Total (Acct. 431):	**811,980**	**706,028**	
Total:	**23,588,438**	**24,225,393**	

DETAIL OF OTHER INCOME STATEMENT ACCOUNTS

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	This Year Amount (b)	Last Year Amount (c)	
Revenues From Merchandising, Jobbing and Contract Work (415):			
MISCELLANEOUS	0	648	1
Total (Acct. 415):	**0**	**648**	
Less: Costs and Exp. Of Merchandising, Job. & Contract Work (416):			
MISCELLANEOUS	0	0	2
Total (Acct. 416):	**0**	**0**	
Revenues From Nonutility Operations (417):			
CONNECT SMART SERVICE	133,871	165,947	3
MISCELLANEOUS	2,890	3,005	4
Total (Acct. 417):	**136,761**	**168,952**	
Less: Expenses of Nonutility Operations (417.1):			
TYRONE LANDS CLEAN UP EXPENSE	45,087	138,382	5
MISCELLANEOUS	34,099	11,506	6
Total (Acct. 417.1):	**79,186**	**149,888**	
Nonoperating Rental Income (418):			
Operation Expense			7
Maintenance Expense			8
Rent Expense			9
Depreciation Expense			10
Amortization Expense			11
Other (specify):			
INCOME FROM MISCELLANEOUS NON-UTILITY RENTAL PROPERTY	6,998	59,304	* 12
Total (Acct. 418):	**6,998**	**59,304**	
Allowance for Other Funds Used During Construction (419.1):			
ELECTRIC	1,263,135	551,981	13
GAS	157,896	67,071	14
Total (Acct. 419.1):	**1,421,031**	**619,052**	
Miscellaneous Nonoperating Income (421):			
SUPPLEMENTAL AFUDC	216,440	279,291	15
TIMBER SALES	83,362	83,844	16
ALLOCATION FROM XCEL ENERGY SERVICES INC.	1,302	20,948	17
MISCELLANEOUS	64	222	18
Total (Acct. 421):	**301,168**	**384,305**	
Gain on Disposition of Property (421.1):			
GAIN ON DISPOSITION OF LAND	0	23,458	19
Total (Acct. 421.1):	**0**	**23,458**	

DETAIL OF OTHER INCOME STATEMENT ACCOUNTS

List items greater than $10,000 separately (others may be grouped). Describe fully using other than account titles.

Particulars (a)	This Year Amount (b)	Last Year Amount (c)	
Loss on Disposition of Property (421.2):			
NONE	0	0	20
Total (Acct. 421.2):	**0**	**0**	
Amort. of Debt. Disc. And Expense (428):			
FIRST MORTGAGE BONDS SERIES DUE DEC 01, 2026	4,096	25,409	21
FIRST MORTGAGE BONDS SERIES DUE OCT 01, 2018	152,090	152,507	22
FIRST MORTGAGE BONDS SERIES DUR SEPT 01, 2038	120,804	36,130	23
SENIOR NOTES SERIES DUE OCT 01, 2018	0	57,884	24
RESOURCE RECOVERY FINANCING DUE NOV 01, 2021	5,465	5,479	25
Total (Acct. 428):	**282,455**	**277,409**	
Amortization of Loss on Reaquired Debt (428.1):			
FIRST MORTGAGE BONDS SERIES DUE MAR 01, 2012 REACQUIRED OCT 1983	246,969	247,646	26
FIRST MORTGAGE BONDS SERIES DUE JUL 01, 2016 REACQUIRED MAR 1993	132,117	132,479	27
FIRST MORTGAGE BONDS SERIES DUE MAR 01, 2018 REACQUIRED MAR 1993	114,831	115,145	28
FIRST MORTGAGE BONDS SERIES DUE OCT 01, 2023 REACQUIRED OCT 2003	332,675	333,586	29
FIRST MORTGAGE BONDS SERIES DUE APR 01, 2021 REACQUIRED DEC 1996	120,239	120,568	30
FIRST MORTGAGE BONDS SERIES DUE DEC 01, 2026 REACQUIRED MAR 2009	(192,310)	0	* 31
RESOURCE RECOVERY FINANCING, REACQUIRED NOV 1996	15,279	15,321	32
Total (Acct. 428.1):	**769,800**	**964,745**	
Less: Amort. of Premium on Debt-Credit (429):			
NONE	0	0	33
Total (Acct. 429):	**0**	**0**	
Less: Amortization of Gain on Reaquired Debt-Credit (429.1):			
NONE	0	0	34
Total (Acct. 429.1):	**0**	**0**	
Less: Allowance for Borrowed Funds Used During Construction-Cr. (432):			
ELECTRIC	726,593	938,503	35
GAS	91,188	114,056	36
Total (Acct. 432):	**817,781**	**1,052,559**	
Extraordinary Income (434):			
NONE	0	0	37
Total (Acct. 434):	**0**	**0**	
Less: Extraordinary Deductions (435):			
NONE	0	0	38
Total (Acct. 435):	**0**	**0**	

DETAIL OF OTHER INCOME STATEMENT ACCOUNTS

Detail of Other Income Statement Accounts (Page F-60)

General footnotes

12. Non-operating rental income reported on this line.

DETAIL OF CERTAIN GENERAL EXPENSE ACCOUNTS

Particulars (a)	This Year Amount (b)	Last Year Amount (c)	
Acct. 922--Administrative Expenses Transferred - Cr.:			
Explain basis of computation of credit in this account.			
ADMINISTRATIVE AND GENERAL TRANSFERRED TO CAPITAL	(167,852)	(141,069)	1
SHARED ASSET COSTS	(2,147,688)	(1,985,808)	2
OTHER	(3,075)	(6,882)	3
Total (Acct. 922):	**(2,318,615)**	**(2,133,759)**	
Acct. 923--Outside Services Employed:			
State total cost, nature of service, and of each person who was paid for services includible in this account, $25,000 or more.			
BOOZ ALLEN & HAMILTON INC	0	341,171	4
DELOITTE AND TOUCHE LLP	215,987	199,662	5
EQUATERRA INC	0	117,228	6
WACKENHUT CORP.	88,164	113,859	7
DELOITTE TAX LLP	26,325	47,766	8
VERIFICATIONS INC.	46,100	75,569	9
IQ NAVIGATOR INC.	722,242	827,390	10
TRANS ALARM INC	32,816	46,404	11
SCOTTDADDEN INC	0	30,786	12
PRICEWATERHOUSECOOPERS LLP	103,872	73,621	13
SAFENET CONSULTING INC	5,215	30,309	14
APOORVA CORPORATION	1,658	27,967	15
NEW YORK STOCK EXCHANGE INC	0	27,014	16
IBM	25,830	0	17
BAYFIELD COUNTY UW EXTENSION	25,250	0	18
INDIVDUAL ITEMS UNDER $25,000	247,144	561,585	19
Total (Acct. 923):	**1,540,603**	**2,520,331**	
Acct. 924--Property Insurance:			
List hereunder major classes of expenses and also state extent (in footnotes) to which utility is self-insured against insurable risks to its property.			
Premiums for insurance	1,263,944	1,023,569	20
Dividends received from insurance companies--cr.			21
Amounts credited to Acct. 261, Property Insurance Reserve			22
Other (specify):			
NONE	0	0	23
Total (Acct. 924):	**1,263,944**	**1,023,569**	
Acct. 925--Injuries and Damages:			
List hereunder major classes of expense. Also, state extent (in footnotes) to which utility is self-insured against risks of injuries and damages to employes or to others.			
Premiums for insurance	1,074,848	763,835	24
Dividends received from insurance companies--cr.			25
Amounts credited to Acct. 262, Injuries and Damages Reserve			26

DETAIL OF CERTAIN GENERAL EXPENSE ACCOUNTS

Particulars (a)	This Year Amount (b)	Last Year Amount (c)	
Acct. 925--Injuries and Damages:			
List hereunder major classes of expense. Also, state extent (in footnotes) to which utility is self-insured against risks of injuries and damages to employes or to others.			
Expenses of investigating and adjusting claims			**27**
Costs of safety and accident-prevention activities			**28**
Other (specify):			
CLAIMS PAYMENT FROM INSURANCE COMPANY	(1,724,286)		**29**
INJURIES AND DAMAGES EXPENSES	584,746	528,044	**30**
Total (Acct. 925):	**(64,692)**	**1,291,879**	
Acct. 926--Employee Pensions and Benefits:			
Report total amount for utility hereunder and show credit for amounts transferred to construction or other accounts, leaving the net balance in Acct. 926.			
Pension accruals or payments to pension fund	2,085,557	699,527	**31**
Pension payments under unfunded basis			**32**
Employees benefits (life, health, accident & hospital insur. etc.)	9,114,491	7,530,587	**33**
Expense of educational and recreational activities for employees			**34**
Other (specify):			
NONE	0	0	**35**
Total (Acct. 926):	**11,200,048**	**8,230,114**	
Acct. 930.2--Miscellaneous General Expenses:			
Industry association dues	322,850	370,125	**36**
Nuclear power research expenses			**37**
Other experimental and general research expenses			**38**
Exp of corporate organization and of servicing outstanding securities of utility	82,541	65,766	**39**
Directors fees and expenses	123,583	195,044	**40**
Other (specify):			
SEC FILING EXPENSES	18,416	26,360	**41**
Total (Acct. 930.2):	**547,390**	**657,295**	

DETAIL OF CERTAIN GENERAL EXPENSE ACCOUNTS

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax amoung the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. Provide the substitute page either in the context of a footnote or within the Appendix.

Particulars (Details) (a)	Amount (b)		
Net Income for the Year	47,362,920		1
Taxable Income Not Reported on Books			
	2,364,128	*	2
Deductions Recorded on Books Not Deducted for Return			
	126,955,597	*	3
Income Recorded on Books Not Included in Return			
	4,320,502	*	4
Deductions on Return Not Charged Against Book Income			
	153,129,986	*	5
Reconciling Items: Equity in Earnings of Subsidiary Companies	(29,642)		6
Total Income Tax Expense	(25,643,465)		7
Federal Tax Net Income	**44,905,264**		
Show Computation of Tax:			
Federal Income Tax at 35%	15,716,842		8
Plus: Other	991,430		9
TOTAL Federal Income Tax Payable	16,708,272	*	10

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes (Page F-62)

General footnotes

2. TAXABLE INCOME NOT REPORTED ON BOOKS:	Amount
Book Income- Wisconsin/ South Dakota AFDC	162,500
Contributions In Aid Construction	2,123,373
Equity Earnings in Subsidiaries	40,202
Subsidiary Dividends	38,053
Total	2,364,128

3. DEDUCTION RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:	Amount
Avoided Cost Interest	1,849,722
Bad Debts	51,248
Book Amortization-Computer Software	4,355,362
Book Amortization-Other	151,643
Book Depreciation	55,763,153
Capitalization of Software Expense	26,706
Clearing Account Book Expense	3,060,314
Club Dues	4,000
Contribution Carryover	876,016
Environmental Remediation	31,738,476
ESOP Dividend	246,024
Lobbying Expenses	294,000
Meals (Travel) and Entertainment	74,000
Medical Deductions Self Insured	5,026
Medicare Reimbursements	120,480
Non Qualified Pension Plans	1,041,810
Performance Share Plan	68,083
Penalties	1,734
Pension Expense (DTL)	559,000
Post Employment Benefits Retiree Medical	1,525,838
Rate Case/Restructuring Expense	139,548
Regulatory Asset-MISO Day 2	3,041,268
Regulatory Asset-Nuclear Decommissioning	2,482,603
Regulatory Liability - MISO Day 2	170,243
Regulatory Liability - IRC Sec 199	322,157
Regulatory Liability Refund Obligation	18,418,370
Regulatory Reserve	274,817
Severance Accrual	76,558
Unbilled Revenue	61,887
Vacation Accrual	155,511
Total	126,955,597

4. INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:

AFDC Equity (Non-CIP)	(1,450,595)
Sale of Emission Allowances	(149,707)
Customer Adv - Construction	(2,720,200)
Total	(4,320,502)

5. DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:

ADR Repair Allowance	(4,184,277)
AFDC Debt (Non-CIP)	(838,750)
Book Unamortized Cost of Retired Debt	(1,490,583)
Deferred Compensation Plan Reserve	(1,280,449)
Deferred Revenue (ITC Grant Accounting)	(44,139)
Dividends Received Deduction	(30,442)
Energy Markets Hedging	(30,592)
Postretirement Benefit Medicare Reimbursement	(502,000)
Gain/Loss on Dispositions (Tax)	(290,759)
Insurance Fund Income (Cash Value)	(207,754)
Inventory Reserve	(2,282)
Interest Income/Expense on Disputed Tax	(154,240)
Internally Developed Software	(1,331,600)
Litigation Reserve	(300,000)
Lower of Cost or Mkt on Gas Invent	(68,017)

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

Nuclear Refueling Outage Costs	(3,961,919)
Pension & Benefits Capitalized	(342,249)
Post Employment Benefits Workmen's Compensation	(816,353)
Prepaid Insurance	(1,090,571)
PUCIP Adjustment	(1,427,950)
Rate Refund Reserve	(1,929,378)
Regulatory Reserve - Environmental	(31,326,383)
Repair Expenditures	(7,629,925)
Section 174 Adjustment	(287,320)
State Income Taxes	(4,168,515)
Tax Depreciation	(85,591,981)
Tax Removal Cost Over Book	(2,791,484)
Wisconsin Annual License Fee	(1,010,074)
Total	(153,129,986)

11. Northern States Power Company (Wisconsin) is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 2009. The other members of the affiliated group and the Federal Income tax provision of each are:

Xcel Energy Inc.	(11,438,918)
Northern States Power Company (Minnesota)	(16,718,678)
Clearwater Investments, Inc.	(609)
NSP Lands, Inc.	(4,861)
Public Service Company of Colorado	(21,847,131)
Southwestern Public Service Company	6,306,880
Xcel Energy Communications Group	3,194,474
Xcel Energy Markets Holdings	(160,300)
Xcel Energy International	878,884
Xcel Energy Retail Holdings	524,106
Xcel Energy Ventures	305,564
Xcel Energy Wholesale Group	4,263,405
Xcel Energy WYCO Inc.	(20,675,816)
WestGas Interstate, Inc.	35,031
Xcel Energy Services Inc.	1,470,365

The consolidated Federal Income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocates the consolidated federal income tax liability among the companies based on the recognition of the benefits/burdens contributed by each member to the consolidated return. Under the stand-alone method, the sum of the amounts allocated to the member companies equals the consolidated amount.

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)	
Electric				1
Operation				2
Production	6,722,124			3
Transmission	2,379,704			4
Distribution	7,594,370			5
Customer Accounts	3,617,662			6
Customer Service and Informational	1,314,045			7
Sales	103,365			8
Administrative and General	9,851,543			9
TOTAL Operation (Total of lines 3 thru 9)	**31,582,813**			10
Maintenance				11
Production	4,111,850			12
Transmission	849,275			13
Distribution	3,296,892			14
Administrative and General				15
TOTAL Maint. (Total of lines 12 thru 15)	**8,258,017**			16
Total Operation and Maintenance				17
Production (Total of lines 3 and 12)	10,833,974			18
Transmission (Total of lines 4 and 13)	3,228,979			19
Distribution (Total of lines 5 and 14)	10,891,262			20
Customer Accounts (Line 6)	3,617,662			21
Customer Service and Informational (Line 7)	1,314,045			22
Sales (Line 8)	103,365			23
Administrative and General (Total of lines 9 and 15)	9,851,543			24
TOTAL Operation and Maintenance (Total of lines 18 thru 24)	**39,840,830**	**1,895,563**	**41,736,393**	25
Gas				26
Operation				27
Production-Manufactured Gas	19,415			28
Production-Nat. Gas (Including Expl. And Dev.)				29
Other Gas Supply	183,782			30
Storage, LNG Terminaling and Processing	82,276			31
Transmission				32
Distribution	3,587,829			33
Customer Accounts	1,331,617			34
Customer Service and Informational	367,347			35
Sales	40,448			36
Administrative and General	1,251,903			37
TOTAL Operation (Total of lines 28 thru 37)	**6,864,617**			38
Maintenance				39

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)	
Production-Manufactured Gas				40
Production-Natural Gas				41
Other Gas Supply				42
Storage, LNG Terminaling and Processing	63,140			43
Transmission				44
Distribution	932,422			45
Administrative and General				46
TOTAL Maint. (Total of lines 40 thru 46)	**995,562**			47
Total Operation and Maintenance				48
Production-Manufactured Gas (Total of lines 28 and 40)	19,415			49
Production-Nat. Gas (Including Expl. And Dev.) (Total lines 29 and 41)				50
Other Gas Supply (Total lines 30 and 42)	183,782			51
Storage, LNG Terminaling and Processing (Total lines 31 and 43)	145,416			52
Transmission (Lines 32 and 44)				53
Distribution (Lines 33 and 45)	4,520,251			54
Customer Accounts (Line 34)	1,331,617			55
Customer Service and Informational (Line 35)	367,347			56
Sales (Line 36)	40,448			57
Administrative and General (Lines 37 and 46)	1,251,903			58
TOTAL Operation and Maint. (Total of lines 49 thru 58)	**7,860,179**	**373,975**	**8,234,154**	59
Other Utility Departments				60
Operation and Maintenance			**0**	61
TOTAL All Utility Dept (Total of lines 25, 59 and 61)	**47,701,009**	**2,269,538**	**49,970,547**	62
Utility Plant				63
Construction (By Utility Departments)				64
Electric Plant	15,591,007	741,795	**16,332,802**	65
Gas Plant	2,754,493	131,054	**2,885,547**	66
Other			**0**	67
TOTAL Construction (Total of lines 65 thru 67)	**18,345,500**	**872,849**	**19,218,349**	68
Plant Removal (By Utility Departments)				69
Electric Plant	770,872	36,677	**807,549**	70
Gas Plant	58,727	2,794	**61,521**	71
Other			**0**	72
TOTAL Plant Removal (Total of lines 70 thru 72)	**829,599**	**39,471**	**869,070**	73
Other Accounts (Specify, provide details in footnote):			**0**	74
Account No. 182.3 Regulatory Assets	1,089,257	51,825	**1,141,082**	75
Accounts No. 415-21 Nonutility	19,487	927	**20,414**	76
Accounts No. 426.1-5 Miscellaneous Income and Deductions	105,198	5,005	**110,203**	77
			0	78

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)	
			0	79
			0	80
			0	81
			0	82
			0	83
			0	84
			0	85
			0	86
			0	87
			0	88
			0	89
			0	90
			0	91
			0	92
			0	93
			0	94
TOTAL Other Accounts	1,213,942	57,757	1,271,699	95
TOTAL SALARIES AND WAGES	68,090,050	3,239,615	71,329,665	96

MISCELLANEOUS GENERAL EXPENSES (ACCT. 930.2) (ELECTRIC)

Description (a)	Amount (b)	
Industry Association Dues	292,166	1
Pub & Dist info to Stkhldrs...expn servicing outstanding Securities	73,488	2
Directors Fees and Expenses	110,034	3
SEC Filing Expenses	16,398	4
Total:	**492,086**	

COMMON PLANT IN SERVICE

1. Include in column (e) entries reclassifying property from one account or utility service to another, etc..
2. Corrections of entries of the current or immediately preceding year should be recorded in columns (c) or (d), accordingly, as they are corrections of additions or retirements.

Account (a)	Balance First of Year (b)	Additions During Year (c)	Retirements During Year (d)		
INTANGIBLE PLANT					
Organization (301)	0				**1**
Franchises and Consents (302)	0				**2**
Miscellaneous Intangible Plant (303)	29,798,422	2,240,561			**3**
Total Intangible Plant	**29,798,422**	**2,240,561**	**0**		
GENERAL PLANT					
Land and Land Rights (389)	1,969,818	230,623			**4**
Structures and Improvements (390)	34,100,960	496,244	7,033		**5**
Office Furniture and Equipment (391)	10,628,994	2,414,504	1,158,038		**6**
Transportation Equipment (392)	2,848,585	149,531			**7**
Stores Equipment (393)	810,058		2,168		**8**
Tools, Shop and Garage Equipment (394)	1,419,388	123,044			**9**
Laboratory Equipment (395)	31,019				**10**
Power Operated Equipment (396)	275,065	4,811			**11**
Communication Equipment (397)	20,527,897	(230)	6,494,303	*	**12**
Miscellaneous Equipment (398)	68,120	3,985			**13**
Other Tangible Property (399)	0				**14**
Asset Retirement Costs for General Plant (399.1)	0				**15**
Total General Plant	**72,679,904**	**3,422,512**	**7,661,542**		
Total utility plant in service	**102,478,326**	**5,663,073**	**7,661,542**		

COMMON PLANT IN SERVICE (cont.)

Account (a)	Adjustments Increase or (Decrease) (e)	Transfers (f)	Balance End of Year Total (g)	Balance End of Year Located in Wisconsin (h)		
Organization (301)			0			1
Franchises and Consents (302)			0			2
Miscellaneous Intangible Plant (303)			32,038,983	32,038,983		3
	0	0	32,038,983	32,038,983		
Land and Land Rights (389)			2,200,441	2,149,312		4
Structures and Improvements (390)			34,590,171	33,596,965		5
Office Furniture and Equipment (391)			11,885,460	11,703,988		6
Transportation Equipment (392)			2,998,116	2,998,116		7
Stores Equipment (393)			807,890	801,319		8
Tools, Shop and Garage Equipment (394)			1,542,432	1,499,312		9
Laboratory Equipment (395)			31,019	30,525		10
Power Operated Equipment (396)			279,876	279,876		11
Communication Equipment (397)			14,033,364	13,278,221	*	12
Miscellaneous Equipment (398)			72,105	70,600		13
Other Tangible Property (399)			0			14
Asset Retirement Costs for General Plant (399.1)			0			15
	0	0	68,440,874	66,408,234		
	0	0	100,479,857	98,447,217		

COMMON PLANT IN SERVICE

Common Plant in Service (Page F-65)

General footnotes

12. Negative additions due to 106 reclass to different 101 plant account.

COMMON PLANT IN SERVICE (cont.)

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COMMON ACCUMULATED DEPRECIATION

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (d)	Accruals During Year: Additional Amount (e)	
Organization (301)	0				1
Franchises and Consents (302)	0				2
Miscellaneous Intangible Plant (303)	20,455,485	Various		3,580,874	3
Total Intangible Plant	**20,455,485**		**0**	**3,580,874**	
Land and Land Rights (389)	0				4
Structures and Improvements (390)	8,588,266	2.860%	811,181		5
Office Furniture and Equipment (391)	6,333,485	Various	1,369,488		6
Transportation Equipment (392)	1,329,820	Various		292,762	7
Stores Equipment (393)	695,264	5.000%	40,498		8
Tools, Shop and Garage Equipment (394)	847,575	5.000%	72,966		9
Laboratory Equipment (395)	20,625	5.000%	1,526		10
Power Operated Equipment (396)	218,334	Various		20,765	11
Communication Equipment (397)	18,556,392	Various	1,292,942		12
Miscellaneous Equipment (398)	62,882	5.000%	819		13
Other Tangible Property (399)	0				14
Asset Retirement Costs for General Plant (399.1)	0				15
Retirement Work in Progress	(267,670)	Various			16
Total General Plant	**36,384,973**		**3,589,420**	**313,527**	
Total accum. prov. for depreciation	**56,840,458**		**3,589,420**	**3,894,401**	

COMMON ACCUMULATED DEPRECIATION (cont.)

Account (a)	Book Cost of Plant Retired (f)	Cost of Removal (g)	Salvage (h)	Adjustments Increase or (Decrease) (i)	Balance End of Year Total (j)	Balance End of Year Located in Wisconsin (k)	
301					**0**		**1**
302					**0**		**2**
303					**24,036,359**	24,036,359	**3**
	0	**0**	**0**	**0**	**24,036,359**	**24,036,359**	
389					**0**		**4**
390	7,033	1,304			**9,391,110**	8,891,560	**5**
391	1,158,038			3,064	**6,547,999**	6,366,526	**6**
392					**1,622,582**	1,622,582	**7**
393	2,168			(831)	**732,763**	726,252	**8**
394				(298)	**920,243**	879,085	**9**
395					**22,151**	21,657	**10**
396				1,103	**240,202**	240,202	**11**
397	6,494,303				**13,355,031**	12,611,626	**12**
398				(3,038)	**60,663**	59,313	**13**
399					**0**		**14**
399.1					**0**		**15**
RWIP		48,832			**(316,502)**	(314,998)	**16**
	7,661,542	**50,136**	**0**	**0**	**32,576,242**	**31,103,805**	
	7,661,542	**50,136**	**0**	**0**	**56,612,601**	**55,140,164**	

COMMON UTILITY PLANT AND ACCUMULATED DEPRECIATION - ALLOCATION TO UTILITY DEPARTMENTS

Particulars (a)	Plant End of Year (b)	Accumulated Depreciation End of Year (c)	Depreciation Accruals (d)		
Electric	89,437,122	50,390,877	3,221,215	*	1
Gas	11,042,735	6,221,724	368,205	*	2
Total:	**100,479,857**	**56,612,601**	**3,589,420**		

COMMON UTILITY PLANT AND ACCUMULATED DEPRECIATION - ALLOCATION TO UTILITY DEPARTMENTS

Common Utility Plant and Accumulated Depreciation - Allocation to Utility Departments (Page F-69)

General footnotes

Explanation of method of allocating common plant, accumulated depreciation, and depreciation expense by utility departments.

Common plant, depreciation reserve and depreciation expense has been allocated to utility departments on the basis of average percentages of utility plant in service, gross revenue and operating expenses (exclusive of joint utility administrative and general expenses, depreciation and taxes) of each department to the total.

Common property under capital leases is not included in these plant numbers.

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (c) and (d), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Regulatory Commission Name (a)	Description (b)	Assessed by Regulatory Commission (c)	Expenses of Utility (d)	Total Expenses for Current year (e)	Deferred in Account 182.3 at Beginning of Year (f)	
Public Service Commission of Wisconsin	4220 UR-115 2008 Retail Rate Case	22,854		**22,854**		1
		0	0	**0**	0	2
	4220 UR-116 2010 Retail Rate Case	153,395	76,419	**229,814**		3
				0		4
	4220-FR-102 Fuel Rules Proceeding	9,646		**9,646**		5
	4220-AU-134 Affiliated Interest with Xcel	5,675		**5,675**		6
				0		7
	4220-GF-108 PGA Filings	3,990		**3,990**		8
	2008-2009 Stray Voltage Assessment	57,724		**57,724**		9
	Remainder Assessment	671,564		**671,564**		10
				0		11
	Miscellaneous Expenses	7,961	27,130	**35,091**		12
				0		13
Michigan Public Service Commission	Public Utility Assessment	36,956		**36,956**		14
				0		15
	Miscellaneous Expense		44,667	**44,667**		16
				0		17
Federal Energy Regulatory Commission	Wholesale Rate Case Expenses		139,548	**139,548**		18
		969,765	**287,764**	**1,257,529**	**0**	

REGULATORY COMMISSION EXPENSES (cont.)

3. Show in column (l) any expenses incurred in prior years which are being amortized. List in column (b) the period of amortization.
4. List in column (g), (h) and (i) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

Expenses Incurred During Year				Amortized During Year			
Currently Charged To							
Department (g)	Account No. (h)	Amount (i)	Deferred to Account 182.3 (j)	Contra Account (k)	Amount (l)	Deferred in Account 182.3 at End of Year (m)	
Electric	928	20,342					1
Gas	928	2,512	0		0	0	2
Electric	928	204,576					3
Gas	928	25,238					4
Electric	928	9,646					5
Electric	928	5,051					6
Gas	928	624					7
Gas	928	3,990					8
Electric	928	57,724					9
Electric	928	502,476					10
Gas	928	169,088					11
Electric	928	28,389					12
Gas	928	6,702					13
Electric	928	23,510					14
Gas	928	13,446					15
Electric	928	44,266					16
Gas	928	401					17
Electric	928	139,548					18
		1,257,529	**0**		**0**	**0**	

ELECTRIC OPERATING REVENUES & EXPENSES

Particulars (a)	This Year (b)	Last Year (c)	
Operating Revenues			
Sales of Electricity			
Sales of Electricity (440-448)	581,103,948	569,618,869	1
(Less) Provision for Rate Refunds (449.1)	25,331,479	9,464,445	2
Total Sales of Electricity	**555,772,469**	**560,154,424**	
Other Operating Revenues			
Forfeited Discounts (450)	827,386	988,718	3
Miscellaneous Service Revenues (451)	450,332	466,705	4
Sales of Water and Water Power (453)	0	0	5
Rent from Electric Property (454)	609,809	659,587	6
Interdepartmental Rents (455)	0	0	7
Other Electric Revenues (456)	4,030,881	(4,392,175)	8
Wheeling (456.1)	0	0	9
Regional Transmission Service Revenues (457.1)	0	0	10
Total Other Operating Revenues	**5,918,408**	**(2,277,165)**	
Total Operating Revenues	**561,690,877**	**557,877,259**	
Operation and Maintenenance Expenses			
Power Production Expenses (500-558)	333,308,294	341,575,888	11
Transmission Expenses (560-573)	(1,793,623)	(3,625,857)	12
Regional Market Expenses (575-576)	0	0	13
Distribution Expenses (580-598)	19,407,930	19,805,087	14
Customer Accounts Expenses (901-905)	11,062,425	10,859,557	15
Customer Service Expenses (907-910)	9,719,265	9,098,190	16
Sales Promotion Expenses (911-916)	191,456	262,180	17
Administration and General Expenses (920-935)	30,341,833	27,281,459	18
Total Operation and Maintenenance Expenses	**402,237,580**	**405,256,504**	
Other Expenses			
Depreciation Expense (403)	48,309,935	45,003,810	19
Amortization of Limited-Term Utility Plant (404)	4,073,459	4,368,676	20
Gain from Disposition of Allowances (411.8)	161,322	161,322	21
Amortization of Other Utility Plant (405)	229,137	289,727	22
Amortization of Utility Plant Acquisition Adjustment (406)	0	0	23
Amortization of Property Losses (407)	0	0	24
Regulatory Debits (407.3)	0	0	25
(Less) Regulatory Credits (407.4)	168,658	168,657	26
Taxes Other Than Income Taxes (408.1)	20,622,215	18,719,425	27
Income Taxes (409.1)	21,411,700	24,713,564	28
Provision for Deferred Income Taxes (410.1, 411.1)	4,844,851	320,192	29
Investment Tax Credits, Restored (411.4)	(604,765)	(600,261)	30
(Less) Gains from Disp. Of Utility Plant (411.6)	0	0	31

ELECTRIC OPERATING REVENUES & EXPENSES

Particulars (a)	This Year (b)	Last Year (c)	
Other Expenses			
Accretion Expense (411.10)	0	0	**32**
Total Other Expenses	**98,556,552**	**92,485,154**	
Total Operating Expenses	**500,794,132**	**497,741,658**	
NET OPERATING INCOME	**60,896,745**	**60,135,601**	

ELECTRIC OPERATING REVENUES (ACCT. 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters. In addition to the number of flat rate accounts, except that where setarate meter readings are addedfor billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous period (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
5. See Important Changes During the Year for important new territory added and important rate increases or decreases.
6. For lines 1, 2, 3 and 4, see Sales of Electricity by Rate Schedules for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

	Operating Revenues		Megawatt Hours Sold		Avg. No. Cust. Per Month			
Particulars (a)	**This Year (b)**	**Last Year (c)**	**This Year (d)**	**Last Year (e)**	**This Year (f)**	**Last Year (g)**		
Sales of Electricity								
Residential Sales (440)	209,255,340	203,739,166	1,944,757	1,938,259	218,431	217,368		1
Farm Sales (441)	0	0	0	0	0	0		2
Small Commercial Sales (442)	226,012,570	224,805,341	2,654,172	2,761,323	41,300	40,950		3
Industrial Sales (442)	110,316,410	102,655,094	1,667,147	1,629,185	90	98	*	4
Public Street & Highway Lighting (444)	4,643,432	4,357,646	26,883	24,721	744	734		5
Public Other Sales (445)	1,082,761	1,109,995	10,583	11,036	421	379		6
Sales to Railroads and Railways (446)	0	0	0	0	0	0		7
Interdepartmental Sales (448)	143,960	183,069	1,756	2,169	43	42		8
Total Sales to Ultimate Customers	**551,454,473**	**536,850,311**	**6,305,298**	**6,366,693**	**261,029**	**259,571**		
Sales for Resale (447)	29,649,475	32,768,558	530,856	553,265	10	10		9
Total Sales of Electricity	**581,103,948**	**569,618,869**	**6,836,154**	**6,919,958**	**261,039**	**259,581**		
(Less) Provision for Rate Refunds (449.1)	25,331,479	9,464,445						10
Total Revenues Net of Provision for Rate Refunds	**555,772,469**	**560,154,424**	**6,836,154**	**6,919,958**	**261,039**	**259,581**		

ELECTRIC OPERATING REVENUES (ACCT. 400)

Electric Operating Revenues (Acct. 400) (Page E-02)

General footnotes

Column b, total sales of electricity includes $9,356,222 of unbilled revenues.

Column d, total sales of electricity includes 122,561 MWH relating to unbilled revenues.

Industrial Sales, Line 4:
Commercial and Industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

ELECTRIC OPERATING REVENUES (ACCT. 400)

OTHER OPERATING REVENUES (ELECTRIC)

1. Report succinct statement of the revenues in each account and show separate totals for each account.
2. Report name of lessee and description of property for major items of rent revenue. Group other rents less than $25,000 by classes.
3. For sales of water and water power, report name of purchaser, purpose for which water used and the development supplying water.
4. Report basis of charges for any interdepartmental rents.
5. Report details of major items in Acct. 456. Group items less than $25,000.

Particulars (a)	Amount (b)	
Wisconsin Geographical Operations		
Forfeited Discounts (450):		
LATE PAYMENT CHARGES	800,930	1
Total Forfeited Discounts (450)	**800,930**	
Miscellaneous Shared Revenues (451):		
SERVICE CONNECTIONS	552,880	2
RETURNED CHECK CHARGE	17,752	3
OTHER MISCELLANEOUS	(126,957)	4
Total Miscellaneous Shared Revenues (451)	**443,675**	
Sales of Water & Water Power (453):		
NONE		5
Total Sales of Water & Water Power (453)	**0**	
Rent from Electric Property (454):		
RENTAL E-LEASES	181,892	6
VARIOUS TELEPHONE & CABLE TV COMPANY	389,619	7
Total Rent from Electric Property (454)	**571,511**	
Interdepartmental Rents (455):		
NONE		8
Total Interdepartmental Rents (455)	**0**	
Other Electric Revenues (456):		
SALES AND USE TAX HANDLING	50,754	9
RESALE FACILITY CHARGES	94,318	10
EEI MUTUAL AID REVENUE	(10,413)	11
NUCLEAR OUTAGE ACCOUNTING CHANGE	3,961,919	12
MISCELLANEOUS	163,391	13
WINDSOURCE	1,044	14
Total Other Electric Revenues (456)	**4,261,013**	
Wheeling (456.1):		
NONE		15
Total Wheeling (456.1)	**0**	
Regional Transmission Service Revenues (457.1):		
NONE		16
Total Regional Transmission Service Revenues (457.1)	**0**	
Total Wisconsin	**6,077,129**	
Out-of-State Geographical Operations		
Forfeited Discounts (450):		
LATE PAYMENT CHARGES	26,456	17
Total Forfeited Discounts (450)	**26,456**	
Miscellaneous Shared Revenues (451):		
SERVICE CONNECTIONS	9,308	18

OTHER OPERATING REVENUES (ELECTRIC)

1. Report succinct statement of the revenues in each account and show separate totals for each account.
2. Report name of lessee and description of property for major items of rent revenue. Group other rents less than $25,000 by classes.
3. For sales of water and water power, report name of purchaser, purpose for which water used and the development supplying water.
4. Report basis of charges for any interdepartmental rents.
5. Report details of major items in Acct. 456. Group items less than $25,000.

Particulars (a)	Amount (b)	
Out-of-State Geographical Operations		
Miscellaneous Shared Revenues (451):		
RETURNED CHECK CHARGE	319	19
OTHER MISCELLANEOUS	(2,970)	20
Total Miscellaneous Shared Revenues (451)	**6,657**	
Sales of Water & Water Power (453):		
NONE		21
Total Sales of Water & Water Power (453)	**0**	
Rent from Electric Property (454):		
RENTAL E-LEASES	3,952	22
VARIOUS TELEPHONE & CABLE TV COMPANY	34,346	23
Total Rent from Electric Property (454)	**38,298**	
Interdepartmental Rents (455):		
NONE		24
Total Interdepartmental Rents (455)	**0**	
Other Electric Revenues (456):		
SALES AND USE TAX HANDLING	1,958	25
EEI MUTUAL AID REVENUE	(429)	26
MI POWER SUPPLY COST RECOVERY	(235,239)	27
MISCELLANEOUS	3,189	28
WINDSOURCE	389	29
Total Other Electric Revenues (456)	**(230,132)**	
Wheeling (456.1):		
NONE		30
Total Wheeling (456.1)	**0**	
Regional Transmission Service Revenues (457.1):		
NONE		31
Total Regional Transmission Service Revenues (457.1)	**0**	
Total Out-of-State	**(158,721)**	
TOTAL UTILITY	**5,918,408**	

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
POWER PRODUCTION EXPENSES					
STEAM POWER GENERATION EXPENSES					
Operation Supervision and Engineering (500)	181,830	93,350	**275,180**	217,449	**1**
Fuel (501)	1,194,053	15,205,111	**16,399,164**	16,346,709	**2**
Steam Expenses (502)	1,213,741	383,481	**1,597,222**	1,543,921	**3**
Steam from Other Sources (503)			**0**	0	**4**
(Less) Steam Transferred -- Credit (504)			**0**	0	**5**
Electric Expenses (505)	584,608	228,152	**812,760**	646,392	**6**
Miscellaneous Steam Power Expenses (506)	463,761	692,607	**1,156,368**	877,278	**7**
Rents (507)		336,034	**336,034**	392,323	**8**
Allowances (509)		452,293	**452,293**	0	**9**
Maintenance Supervision and Engineering (510)	16,877	2,787	**19,664**	22,222	**10**
Maintenance of Structures (511)	313,803	177,696	**491,499**	367,336	**11**
Maintenance of Boiler Plant (512)	626,596	1,376,862	**2,003,458**	1,781,789	**12**
Maintenance of Electric Plant (513)	80,613	79,025	**159,638**	991,815	**13**
Maintenance of Miscellaneous Steam Plant (514)	450,007	307,728	**757,735**	767,309	**14**
Total Steam Power Generation Expenses	**5,125,889**	**19,335,126**	**24,461,015**	**23,954,543**	
NUCLEAR POWER GENERATION EXPENSES					
Operation Supervision and Engineering (517)			**0**	0	**15**
Fuel (518)			**0**	0	**16**
Coolants and Water (519)			**0**	0	**17**
Steam Expenses (520)			**0**	0	**18**
Steam from Other Sources (521)			**0**	0	**19**
(Less) Steam Transferred -- Credit (522)			**0**	0	**20**
Electric Expenses (523)			**0**	0	**21**
Miscellaneous Nuclear Power Expenses (524)			**0**	0	**22**
Rents (525)			**0**	0	**23**
Maintenance Supervision and Engineering (528)			**0**	0	**24**
Maintenance of Structures (529)			**0**	0	**25**
Maintenance of Reactor Plant Equipment (530)			**0**	0	**26**
Maintenance of Electric Plant (531)			**0**	0	**27**
Maintenance of Miscellaneous Nuclear Plant (532)			**0**	0	**28**
Total Nuclear Power Generation Expenses	**0**	**0**	**0**	**0**	
HYDRAULIC POWER GENERATION EXPENSES					
Operation Supervision and Engineering (535)	702,803	65,452	**768,255**	663,275	**29**
Water for Power (536)		554,441	**554,441**	485,651	**30**
Hydraulic Expenses (537)	89,572	1,558	**91,130**	258,883	**31**
Electric Expenses (538)	1,491,414	15,909	**1,507,323**	1,737,414	**32**
Miscellaneous Hydraulic Power Generation Expenses (539)	336,944	1,562,735	**1,899,679**	1,975,665	**33**
Rents (540)		410,688	**410,688**	421,280	**34**
Maintenance Supervision and Engineering (541)	394,692	350,400	**745,092**	776,054	**35**
Maintenance of Structures (542)	164,964	80,217	**245,181**	247,436	**36**
Maintenance of Reservoirs, Dams and Waterways (543)	340,852	398,254	**739,106**	809,345	**37**

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
POWER PRODUCTION EXPENSES					
HYDRAULIC POWER GENERATION EXPENSES					
Maintenance of Electric Plant (544)	1,048,812	307,443	**1,356,255**	1,353,532	**38**
Maintenance of Miscellaneous Hydraulic Plant (545)	99,786	115,778	**215,564**	136,497	**39**
Total Hydraulic Power Generation Expenses	**4,669,839**	**3,862,875**	**8,532,714**	**8,865,032**	
OTHER POWER GENERATION EXPENSES					
Operation Supervision and Engineering (546)	73,785	45,998	**119,783**	113,557	**40**
Fuel (547)		1,914,714	**1,914,714**	4,601,367	**41**
Generation Expenses (548)	280,958	1,533	**282,491**	233,437	**42**
Miscellaneous Other Power Generation Expenses (549)	88,265	288,903	**377,168**	354,740	**43**
Rents (550)		113,497	**113,497**	109,641	**44**
Maintenance Supervision and Engineering (551)	6,885	1,013	**7,898**	7,187	**45**
Maintenance of Structures (552)	93,308	149,392	**242,700**	317,547	**46**
Maintenance of Generating and Electric Plant (553)	462,028	2,099,540	**2,561,568**	3,130,574	**47**
Maintenance of Miscellaneous Other Power Generation Plant (554)	12,625	5,876	**18,501**	17,589	**48**
Total Other Power Generation Expenses	**1,017,854**	**4,620,466**	**5,638,320**	**8,885,639**	
OTHER POWER SUPPLY EXPENSES					
Purchased Power (555)			**0**	0	**49**
System Control and Load Dispatching (556)	20,392	15,153	**35,545**	32,808	**50**
Other Expenses (557)		294,640,700	**294,640,700**	299,837,866	**51**
Precertification Expenses (558)			**0**	0	**52**
Total Other Power Supply Expenses	**20,392**	**294,655,853**	**294,676,245**	**299,870,674**	
Total Power Production Expenses	**10,833,974**	**322,474,320**	**333,308,294**	**341,575,888**	
TRANSMISSION EXPENSES					
Operation Supervision and Engineering (560)	645,664	189,252	**834,916**	771,543	**53**
Load Dispatching (561)			**0**	0	**54**
Load Dispatch-Reliability (561.1)	6,000		**6,000**	0	**55**
Load Dispatch-Monitor and Operate Transmission System (561.2)	1,014,977	314,894	**1,329,871**	1,327,176	**56**
Load Dispatch-Transmission Service and Scheduling (561.3)			**0**	0	**57**
Scheduling, System Control and Dispatch Services (561.4)			**0**	0	**58**
Reliability, Planning and Standards Development Services (561.5)			**0**	534	**59**
Transmission Service Studies (561.6)			**0**	0	**60**
Generation Interconnection Studies (561.7)			**0**	0	**61**
Reliability, Planning and Standards Development Services (561.8)			**0**	0	**62**
Station Expenses (562)	120,795	110,246	**231,041**	251,403	**63**
Overhead Lines Expenses (563)	239,096	320,438	**559,534**	389,561	**64**
Underground Lines Expenses (564)		1,195	**1,195**	856	**65**
Transmission of Electricity by Others (565)			**0**	0	**66**
Miscellaneous Transmission Expenses (566)	350,479	(8,612,079)	**(8,261,600)**	(9,586,445)	**67**

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
TRANSMISSION EXPENSES					
Rents (567)	2,693	373,451	**376,144**	354,068	**68**
Maintenance Supervision and Engineering (568)	28,343	1,316	**29,659**	28,084	**69**
Maintenance of Structures (569)			**0**	0	**70**
Maintenance of Computer Hardware (569.1)			**0**	0	**71**
Maintenance of Computer Software (569.2)			**0**	0	**72**
Maintenance of Communication Equipment (569.3)			**0**	0	**73**
Maintenance of Miscellaneous Regional Transmission Plant (569.4)			**0**	0	**74**
Maintenance of Station Equipment (570)	721,237	435,064	**1,156,301**	1,120,943	**75**
Maintenance of Overhead Lines (571)	95,084	1,736,127	**1,831,211**	1,708,935	**76**
Maintenance of Underground Lines (572)			**0**	0	**77**
Maintenance of Miscellaneous Transmission Plant (573)	4,611	107,494	**112,105**	7,485	**78**
Total Transmission Expenses	**3,228,979**	**(5,022,602)**	**(1,793,623)**	**(3,625,857)**	
REGIONAL MARKET EXPENSES					
Operation Supervision (575.1)			**0**	0	**79**
Day-Ahead and Real-Time Market Facilitation (575.2)			**0**	0	**80**
Transmission Rights Market Facilitation (575.3)			**0**	0	**81**
Capacity Market Facilitation (575.4)			**0**	0	**82**
Ancillary Services Market Facilitation (575.5)			**0**	0	**83**
Market Monitoring and Compliance (575.6)			**0**	0	**84**
Market Facilitation, Monitoring and Compliance Services (575.7)			**0**	0	**85**
Rents (575.8)			**0**	0	**86**
Maintenance of Structures and Improvements (576.1)			**0**	0	**87**
Maintenance of Computer Hardware (576.2)			**0**	0	**88**
Maintenance of Computer Software (576.3)			**0**	0	**89**
Maintenance of Communication Equipment (576.4)			**0**	0	**90**
Maintenance of Miscellaneous Market Operation Plant (576.5)			**0**	0	**91**
Total Regional Market Expenses	**0**	**0**	**0**	**0**	
DISTRIBUTION EXPENSES					
Operation Supervision and Engineering (580)	1,539,084	349,363	**1,888,447**	1,808,213	**92**
Load Dispatching (581)	596,698	99,279	**695,977**	705,139	**93**
Station Expenses (582)	207,582	126,805	**334,387**	373,789	**94**
Overhead Line Expenses (583)	752,301	31,206	**783,507**	437,897	**95**
Underground Line Expenses (584)	1,019,864	(24,372)	**995,492**	1,075,360	**96**
Street Lighting and Signal System Expenses (585)	188,549	134,204	**322,753**	294,157	**97**
Meter Expenses (586)	962,506	(334,895)	**627,611**	574,088	**98**
Customer Installations Expenses (587)	399,818	(358,564)	**41,254**	317,467 *	**99**
Miscellaneous Expenses (588)	1,927,968	2,556,084	**4,484,052**	4,656,043	**100**
Rents (589)		881,592	**881,592**	936,517	**101**
Maintenance Supervision and Engineering (590)	127,369	568	**127,937**	248,114	**102**

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
DISTRIBUTION EXPENSES					
Maintenance of Structures (591)			**0**	0	**103**
Maintenance of Station Equipment (592)	714,564	338,341	**1,052,905**	1,111,257	**104**
Maintenance of Overhead Lines (593)	1,566,912	4,177,079	**5,743,991**	5,866,541	**105**
Maintenance of Underground Lines (594)	772,333	418,634	**1,190,967**	1,210,972	**106**
Maintenance of Line Transformers (595)	5,236	35,234	**40,470**	17,561	**107**
Maintenance of Street Lighting and Signal Systems (596)	79,550	82,993	**162,543**	141,261	**108**
Maintenance of Meters (597)	30,125	3,117	**33,242**	30,369	**109**
Maintenance of Miscellaneous Distribution Plant (598)	803		**803**	342	**110**
Total Distribution Expenses	**10,891,262**	**8,516,668**	**19,407,930**	**19,805,087**	
CUSTOMER ACCOUNTS EXPENSES					
Supervision (901)	33,594	6,765	**40,359**	48,022	**111**
Meter Reading Expenses (902)	1,708,876	1,480,616	**3,189,492**	3,031,453	**112**
Customer Records and Collection Expenses (903)	1,875,192	2,302,217	**4,177,409**	4,031,651	**113**
Uncollectible Accounts (904)		3,267,430	**3,267,430**	3,365,572	**114**
Miscellaneous Customer Accounts Expenses (905)		387,735	**387,735**	382,859	**115**
Total Customer Accounts Expenses	**3,617,662**	**7,444,763**	**11,062,425**	**10,859,557**	
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
Supervision (907)			**0**	0	**116**
Customer Assistance Expenses (908)	1,314,045	8,081,864	**9,395,909**	8,877,634	**117**
Informational and Instructional Expenses (909)		323,356	**323,356**	220,556	**118**
Miscellaneous Customer Service and Informational Expenses (910)			**0**	0	**119**
Total Customer Service and Informational Expenses	**1,314,045**	**8,405,220**	**9,719,265**	**9,098,190**	
SALES EXPENSES					
Supervision (911)			**0**	0	**120**
Demonstrating and Selling Expenses (912)	103,365	88,091	**191,456**	262,180	**121**
Advertising Expenses (913)			**0**	0	**122**
Miscellaneous Sales Expenses (916)			**0**	0	**123**
Total Sales Expenses	**103,365**	**88,091**	**191,456**	**262,180**	
ADMINISTRATIVE AND GENERAL EXPENSES					
Administrative and General Salaries (920)	9,849,068		**9,849,068**	7,264,400	**124**
Office Supplies and Expenses (921)	1,895	6,826,952	**6,828,847**	6,649,364	**125**
(Less) Administrative Expenses Transferred -- Credit (922)		2,064,719	**2,064,719**	1,902,692	**126**
Outside Services Employed (923)		1,300,613	**1,300,613**	2,188,287	**127**
Property Insurance (924)		1,125,559	**1,125,559**	912,724	**128**
Injuries and Damages (925)	494,822	(833,394)	**(338,572)**	1,060,231	**129**
Employee Pensions and Benefits (926)	9,359,003		**9,359,003**	6,932,500	**130**
Franchise Requirements (927)			**0**	0	**131**

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
ADMINISTRATIVE AND GENERAL EXPENSES					
Regulatory Commission Expenses (928)		1,035,528	**1,035,528**	961,861	**132**
(Less) Duplicate Charges -- Credit (929)		549,707	**549,707**	630,048	**133**
General Advertising Expenses (930.1)	580	485,030	**485,610**	529,203	**134**
Miscellaneous General Expenses (930.2)		492,086	**492,086**	596,988	**135**
Rents (931)		2,743,672	**2,743,672**	2,641,884	**136**
Maintenance of General Plant (935)		74,845	**74,845**	76,757	**137**
Total Administrative and General Expenses	**19,705,368**	**10,636,465**	**30,341,833**	**27,281,459**	
Total Operation and Maintenance Expenses	**49,694,655**	**352,542,925**	**402,237,580**	**405,256,504**	

ELECTRIC OPERATION & MAINTENANCE EXPENSES

Electric Operation & Maintenance Expenses (Page E-04)

General footnotes

FERC 587:

Collections on non-gratuitous customer required moves.

ELECTRIC EXPENSES

Report all amounts on the basis and in conformity with the uniform system of accounts and accounting directives prescribed by this commission. Allocate "Total Operations" amounts jurisdictionally between Wisconsin (PSCW) jurisdiction and all other jurisdiction.

	Wisconsin Jurisdictional Operations		Other Jurisdictional Operations			
Particulars (a)	Labor (b)	Other (c)	Labor (d)	Other (e)	Total Operations (f)	
Operation and Maintenenance Expenses						
Power Production Expenses (500-558)	10,593,770	315,593,236	240,204	6,881,084	**333,308,294**	1
Transmission Expenses (560-573)	3,156,789	(4,910,624)	72,190	(111,978)	**(1,793,623)**	2
Regional Market Expenses (575-576)					**0**	3
Distribution Expenses (580-598)	10,573,848	8,217,488	317,414	299,180	**19,407,930**	4
Customer Accounts Expenses (901-905)	3,481,662	7,215,964	136,000	228,799	**11,062,425**	5
Customer Service Expenses (907-910)	1,264,683	8,367,803	49,362	37,417	**9,719,265**	6
Sales Promotion Expenses (911-916)	99,482	84,781	3,883	3,310	**191,456**	7
Administration and General Expenses (920-935)	19,164,728	10,307,321	540,640	329,144	**30,341,833**	8
Total Operation and Maintenenance Expenses	**48,334,962**	**344,875,969**	**1,359,693**	**7,666,956**	**402,237,580**	
Other Expenses						
Depreciation Expense (403)		47,047,993		1,261,942	**48,309,935**	9
Amortization of Limited-Term Utility Plant (404)		3,964,052		109,407	**4,073,459**	10
Gain from Disposition of Allowances (411.8)		157,869		3,453	**161,322**	11
Amortization of Other Utility Plant (405)		223,592		5,545	**229,137**	12
Amortization of Utility Plant Acquisition Adjustment (406)					**0**	13
Amortization of Property Losses (407)					**0**	14
Regulatory Debits (407.3)					**0**	15
(Less) Regulatory Credits (407.4)		168,658			**168,658**	16
Taxes Other Than Income Taxes (408.1)		20,149,713		472,502	**20,622,215**	17
Income Taxes (409.1)		21,214,238		197,462	**21,411,700**	18
Provision for Deferred Income Taxes (410.1, 411.1)		4,785,755		59,096	**4,844,851**	19
Investment Tax Credits, Restored (411.4)		(590,052)		(14,713)	**(604,765)**	20
(Less) Gains from Disp. Of Utility Plant (411.6)					**0**	21
Accretion Expense (411.10)					**0**	22
Total Other Expenses	**0**	**96,468,764**	**0**	**2,087,788**	**98,556,552**	
Total Operating Expenses	**48,334,962**	**441,344,733**	**1,359,693**	**9,754,744**	**500,794,132**	

SALES FOR RESALE (ACCOUNT 447)

1. Report all sales for resale (i.e., sales to purchaser other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule.
2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractural terms and conditions of the service as follows:
   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
   LF - for long-term service. "Long-term" means five years or longer and "firm" means that the service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the needs of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.
   SF - for short-term service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
   LU - for Long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availibility and reliability of designated unit.

Name of Company or Public Authority (Explain Affiliation in Footnote) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	
Village of Bangor, WI	RQ	RS112	5	6	N/A	1
City of Barron, WI	RQ	RS103	13	15	N/A	2
City of Bloomer, WI	RQ	RS106	8	9	N/A	3
Village of Cadott, WI	RQ	RS104	2	3	N/A	4
City of Cornell, WI	RQ	RS113	2	3	N/A	5
City of Medford, WI	RQ	RS9	22	26	N/A	6
City of Rice Lake, WI	RQ	RS8	27	32	N/A	7
City of Spooner, WI	RQ	RS105	6	7	N/A	8
Village of Trempealeau, WI	RQ	RS108	3	3	N/A	9
City of Wakefield, MI	RQ	RS107	2	3	N/A	10
Unbilled	RQ					11

SALES FOR RESALE (ACCOUNT 447) (cont.)

IU - for Intermediate-term service from a designated generating unit. The same as LU service except that "Intermediate-term" means longer than one year but less than five years.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm serviceregardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule or Tariff Number. On separate lines, list all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
5. For requirements RQ sales and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, leave columns (d), (e) and (f) blank. Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
7. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
8. Footnote entries as required and provide explanations following all required data.

		Revenue				
	MegaWatt Hours Sold (g)	**Demand Charges (h)**	**Energy Charges (i)**	**Other Charges (j)**	**Total Charges (k)**	
	28,685	502,104	1,105,030	4,800	1,611,934	**1**
	82,427	1,119,878	3,200,928	4,800	4,325,606	**2**
	48,879	803,104	1,840,760	4,628	2,648,492	**3**
	13,811	233,409	520,850	4,628	758,887	**4**
	13,647	226,712	527,210	4,800	758,722	**5**
	127,760	2,239,818	4,945,567	4,800	7,190,185	**6**
	155,726	2,765,628	6,131,108	4,800	8,901,536	**7**
	34,107	579,530	1,330,855	4,800	1,915,185	**8**
	14,397	263,211	564,251	4,800	832,262	**9**
	13,823	212,498	505,255	4,628	722,381	**10**
	(2,406)			(15,715)	(15,715)	**11**
Subtotal RQ:	**530,856**	**8,945,892**	**20,671,814**	**31,769**	**29,649,475**	
Subtotal non-RQ:	**0**	**0**	**0**	**0**	**0**	
Total:	**530,856**	**8,945,892**	**20,671,814**	**31,769**	**29,649,475**	

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (c)	MWh (d)	Avg. No. of Customers (e)	
Wisconsin Geographical Operations					
Residential Sales (440)					
WATER HEATING	B00	123,217	1,250	402	1
RESIDENTIAL	B01	181,414,218	1,656,665	193,009	2
RESIDENTIAL TOD	B02	10,968,149	121,041	7,807	3
RESIDENTIAL MANAGED SERVICE	B03	26,662	401	52	4
FARM SERVICE	B04	9,297,535	90,444	4,049	5
FARM SERVICE	B08	10,667	108	14	6
OPTIONAL OFF PEAK	B11	88,609	1,387	110	7
AUTOMATIC PROTECTIVE LIGHTING	B30	475,411	3,172	4,880	8
CONTROLLED WATER HEATING	B37	2,192	20	9	9
Subtotal - Billed Sales		**202,406,660**	**1,874,488**	**210,332**	
Unbilled Residential Sales		1,525,376	14,846		10
Total Sales for Residential Sales (440)		**203,932,036**	**1,889,334**	**210,332**	
Farm Sales (441)					
					11
Subtotal - Billed Sales		**0**	**0**	**0**	
Unbilled Farm Sales					12
Total Sales for Farm Sales (441)		**0**	**0**	**0**	
Small Commercial Sales (442)					
SMALL GENERAL TOD	B05	437,463	4,859	231	13
SMALL GENERAL SERVICE	B06	39,067,078	368,485	27,042	14
SMALL GENERAL SERVICE	B07	11,830	117	16	15
SMALL GENERAL SERVICE	B09	1,094,728	8,867	1,653	16
GENERAL SERVICE	B10	78,536,050	914,297	6,321	17
OPTIONAL OFF SERVICE	B11	231,769	4,259	139	18
PEAK CONTROLLED GENERAL	B12	2,788,209	35,597	104	19
LARGE TOD	B13	83,917,108	1,062,500	835	20
PEAK CONTROLLED TIME	B14	13,414,343	182,796	124	21
PEAK CONTROLLED TOD	B20				22
AUTOMATIC PROTECTIVE	B30	494,252	4,598	3,445	23
MILITARY DISTRIBUTION SERVICE	B45	507,848			24
Subtotal - Billed Sales		**220,500,678**	**2,586,375**	**39,910**	

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (c)	MWh (d)	Avg. No. of Customers (e)	
Wisconsin Geographical Operations					
Small Commercial Sales (442)					
Unbilled Small Commercial Sales		1,463,231	19,780		25
Total Sales for Small Commercial Sales (442)		**221,963,909**	**2,606,155**	**39,910**	
Industrial Sales (442)					
LARGE GENERAL SERVICE	B06	1,404	14	1	26
LARGE TOD	B13	53,528,508	773,267	55	27
PEAK CONTROLLED TIME	B14	34,328,226	545,443	25	28
EXPERIMENTAL RTP	B60	14,034,363	227,612	7	29
Subtotal - Billed Sales		**101,892,501**	**1,546,336**	**88**	
Unbilled Industrial Sales		6,479,048	91,896		30
Total Sales for Industrial Sales (442)		**108,371,549**	**1,638,232**	**88**	
Public Street & Highway Lighting (444)					
COMPANY OWNED STREET LIGHTING	B31	3,248,285	13,540	450	31
COMPANY OWNED STREET LIGHTING	B32	6,634	66	3	32
COMPANY OWNED STREET LIGHTING	B33	550,290	7,846	113	33
COMPANY OWNED STREET LIGHTING	B34	33,730	197	9	34
UNDERGROUND AREA LIGHTING	B35	285,017	873	72	35
STREET LIGHTING SERVICE	B36	63,029	1,065	44	36
UNDERGROUND AREA LIGHTING	B38	31,318	97	34	37
Subtotal - Billed Sales		**4,218,303**	**23,684**	**725**	
Unbilled Public Street & Highway Lighting		241,895	1,592		38
Total Sales for Public Street & Highway Lighting (444)		**4,460,198**	**25,276**	**725**	
Public Other Sales (445)					
FIRE SIREN SERVICE	B20	2,705		89	39
MUNICIPAL WATER PUMPING	B22	1,047,257	10,145	298	40
Subtotal - Billed Sales		**1,049,962**	**10,145**	**387**	
Unbilled Public Other Sales		(47,467)	(477)		41
Total Sales for Public Other Sales (445)		**1,002,495**	**9,668**	**387**	

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (c)	MWh (d)	Avg. No. of Customers (e)	
Wisconsin Geographical Operations					
Sales to Railroads and Railways (446)					
					42
Subtotal - Billed Sales		**0**	**0**	**0**	
Unbilled Sales to Railroads and Railways					43
Total Sales for Sales to Railroads and Railways (446)		**0**	**0**	**0**	
Interdepartmental Sales (448)					
INTERDEPARTMENTAL		139,993	1,717	36	44
Subtotal - Billed Sales		**139,993**	**1,717**	**36**	
Unbilled Interdepartmental Sales					45
Total Sales for Interdepartmental Sales (448)		**139,993**	**1,717**	**36**	
Total Wisconsin		**539,870,180**	**6,170,382**	**251,478**	

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (c)	MWh (d)	Avg. No. of Customers (e)	
Out-of-State Geographical Operations					
Residential Sales (440)					
RESIDENTIAL	C01	5,165,849	53,505	7,792	46
RESIDENTIAL TOD	C02	125,530	1,540	122	47
AUTOMATIC OUTDOOR	C04	17,620	116	185	48
Subtotal - Billed Sales		**5,308,999**	**55,161**	**8,099**	
Unbilled Residential Sales		14,305	262		49
Total Sales for Residential Sales (440)		**5,323,304**	**55,423**	**8,099**	
Farm Sales (441)					
					50
Subtotal - Billed Sales		**0**	**0**	**0**	
Unbilled Farm Sales					51
Total Sales for Farm Sales (441)		**0**	**0**	**0**	
Small Commercial Sales (442)					
AUTOMATIC OUTDOOR LIGHTING	C04	20,705	180	122	52
SMALL COMMERCIAL UNMETERED	C09	36,356	339	53	53
SMALL COMMERCIAL	C10	1,320,987	13,338	1,064	54
TIME OF DAY	C11	1,964	19	2	55
COMMERCIAL	C12	1,676,331	19,836	130	56
INDUSTRIAL RATE SCHEDULE	C13	1,216,062	15,837	15	57
PEAK CONTROLLED TOD	C20	170,262	2,666	3	58
PEAK CONTROLLED GENERAL	C21	13,123	163	1	59
Subtotal - Billed Sales		**4,455,790**	**52,378**	**1,390**	
Unbilled Small Commercial Sales		(407,129)	(4,361)		60
Total Sales for Small Commercial Sales (442)		**4,048,661**	**48,017**	**1,390**	
Industrial Sales (442)					
PEAK CONTROLLED TOD	C20	1,837,943	27,434	2	61
Subtotal - Billed Sales		**1,837,943**	**27,434**	**2**	
Unbilled Industrial Sales		106,918	1,481		62
Total Sales for Industrial Sales (442)		**1,944,861**	**28,915**	**2**	

SALES OF ELECTRICITY BY RATE SCHEDULE

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, and average number of customers, excluding data for Sales for Resale.
2. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), indicate in a footnote the number of such duplicate customers included in the classification.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause, state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Type of Sales/Rate Class Title (a)	Rate Schedule (b)	Revenues (c)	MWh (d)	Avg. No. of Customers (e)	
Out-of-State Geographical Operations					
Public Street & Highway Lighting (444)					
STREET LIGHTING	C30	180,910	1,595	19	63
Subtotal - Billed Sales		**180,910**	**1,595**	**19**	
Unbilled Public Street & Highway Lighting		2,324	12		64
Total Sales for Public Street & Highway Lighting (444)		**183,234**	**1,607**	**19**	
Public Other Sales (445)					
MUNICIPAL PUMPING SERVICE	C32	86,632	979	34	65
Subtotal - Billed Sales		**86,632**	**979**	**34**	
Unbilled Public Other Sales		(6,366)	(64)		66
Total Sales for Public Other Sales (445)		**80,266**	**915**	**34**	
Sales to Railroads and Railways (446)					
					67
Subtotal - Billed Sales		**0**	**0**	**0**	
Unbilled Sales to Railroads and Railways					68
Total Sales for Sales to Railroads and Railways (446)		**0**	**0**	**0**	
Interdepartmental Sales (448)					
INTERDEPARTMENTAL		3,967	39	7	69
Subtotal - Billed Sales		**3,967**	**39**	**7**	
Unbilled Interdepartmental Sales					70
Total Sales for Interdepartmental Sales (448)		**3,967**	**39**	**7**	
Total Out-of-State		**11,584,293**	**134,916**	**9,551**	
TOTAL UTILITY		**551,454,473**	**6,305,298**	**261,029**	

SALES OF ELECTRICITY BY RATE SCHEDULE

Sales of Electricity by Rate Schedule (Page E-08)

If the same customers are served under more than one rate schedule in the same revenue account classification, please indicate the classification and the number of such duplicate customers included.

Due to conversion to a new billing system in 2005, we no longer have this information available.

SALES OF ELECTRICITY BY RATE SCHEDULE

Sales of Electricity by Rate Schedule (Page E-08)

If any rate schedule has a fuel adjustment clause, please indicate the rate schedule and state the estimated additional revenue billed pursuant thereto.

STATE OF MICHIGAN

Estimated Additional Revenue Collected Through Fuel Clause Adjustment:

Rate Code	Revenue
C01	$ 1,186,751
C02	35,179
C04	2,511
Total Residential	$ 1,224,441
C04	$ 3,891
C09	7,665
C10	293,906
C11	393
C12	435,480
C13	339,232
C20	648,203
C21	3,663
Total Commercial & Industrial	$ 1,732,433
C30	$ 19,104
Total Steet Lighting	$ 19,104
C32	$ 21,715
Total Other Sales	$ 21,715
Total Michigan PSCR Revenue	$ 2,997,693

STATE OF WISCONSIN

Estimated Fuel Refunded to Customers Through Base Rates:

Rate Code	Revenue
B00	$ 1,132
B01	1,500,980
B02	109,667
B03	363
B04	81,946
B08	98
B11	1,257
B30	2,874
B37	18
Total Residential	$ 1,698,335
B05	$ 4,585
B06	347,750
B07	110
B09	8,368
B10	862,818
B11	4,019
B12	33,593
B13	1,710,861
B14	672,041
B30	4,339
B60	208,455
Total Commercial and Industrial	$ 3,856,939
B31	$ 11,582
B32	56
B33	6,711
B34	168
B35	747
B36	911
B38	83
Total Street Lighting	$ 20,258

SALES OF ELECTRICITY BY RATE SCHEDULE

B22	$	10,128
Total Other Sales	$	10,128
Interdepartmental	$	2,340
Total Wisconsin Fuel Surcharge	$	5,588,000

NUCLEAR FUEL MATERIALS (ACCOUNT 120.1 THROUGH 120.6 AND 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, explain in footnote the amount of nuclear fuel leased, the quantity used and the quantity on hand, and the costs incurred under such leasing arrangements.

Description of Item (a)	Balance First of Year (b)	Changes during Year: Additions (c)	Changes during Year: Amortization (d)	Changes during Year: Other Reductions (e)	Balance End of Year (f)	
Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)	0				**0**	**1**
Fabrication	0				**0**	**2**
Nuclear Materials	0				**0**	**3**
Allowance for Funds Used during Construction	0				**0**	**4**
(Other Overhead Construction Costs, provide details in footnote)	0				**0**	**5**
SUBTOTAL (Total 2 thru 5)	**0**				0	**6**
Nuclear Fuel Materials and Assemblies	0				**0**	**7**
In Stock (120.2)	0				**0**	**8**
In Reactor (120.3)	0				**0**	**9**
SUBTOTAL (Total 8 & 9)	**0**				0	**10**
Spent Nuclear Fuel (120.4)	0				**0**	**11**
Nuclear Fuel Under Capital Leases (120.6)	0				**0**	**12**
(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	0				**0**	**13**
TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	**0**				0	**14**
Estimated net Salvage Value of Nuclear Materials in line 9	0				**0**	**15**
Estimated net Salvage Value of Nuclear Materials in line 11	0				**0**	**16**
Est Net Salvage Value of Nuclear Materials in Chemical Processing	0				**0**	**17**
Nuclear Materials held for Sale (157)	0				**0**	**18**
Uranium	0				**0**	**19**
Plutonium	0				**0**	**20**
Other (provide details in footnote):	0				**0**	**21**
TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)	**0**				0	**22**

PURCHASED POWER (ACCOUNT 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractural terms and conditions of the service as follows:
   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
   LF - for long-term service. "Long-term" means five years or longer and "firm" means that the service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the needs of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.
   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but less than five years.
   SF - for short-term service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
   LU - for Long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availibility and reliability of designated unit.
   IU - for Intermediate-term service from a designated generating unit. The same as LU service except that "Intermediate-term" means longer than one year but less than five years.
   EX - for exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)		
Northern States Power Company - MN **						*	1
Northern States Power Company - MN **	AD					*	2
** All transactions involving							3
Purchased Power and Sales to Other							4
are included in and shared through the							5
Interchange Agreement with utility							6
affiliate (NSP-MN).							7
Total							

PURCHASED POWER (ACCOUNT 555) (cont.)

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm serviceregardless of the length of the contract and service from designated units of less than one year. Describe the nature of the service in a footnote.

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, leave columns (d), (e) and (f) blank. Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatt hours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (1) includes credits or charges other than the incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. Footnote entries as required and provide explanations following all required data.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER					
MegaWatt Hours Purchased (g)	**MegaWatt Hours Received (h)**	**MegaWatt Hours Delivered (i)**	**Demand Charges (j)**	**Energy Charges (k)**	**Other Charges (l)**	**Total (j+k+l) of Settlement (m)**		
6,643,933					288,194,154	**288,194,154**	*	1
					343,102	**343,102**	*	2
						0		3
						0		4
						0		5
						0		6
						0		7
6,643,933	**0**	**0**	**0**	**0**	**288,537,256**	**288,537,256**		

PURCHASED POWER (ACCOUNT 555)

Purchased Power (Account 555) (Page E-10)

General footnotes

Adjustments primarily relate to true-up of estimated December 2008 energy requirements to actual energy requirements and true-up of estimated 2008 Interchange Agreement Fixed Charges to actual 2008 Interchange Agreement Fixed Charges.

Explain affiliations (column a).

Ownership Interest or Affiliation:

Northern States Power Co. (a Wisconsin Corporation) and Northern States Power Co. (a Minnesota Corporation) are both wholly owned operating subsidiaries of Xcel Energy Inc.

PURCHASED POWER (ACCOUNT 555) (cont.)

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ELECTRIC UTILITY PLANT IN SERVICE

1. Report below the original cost of utility plant in service according to the prescribed accounts.
2. Corrections to prior entries for plant additions and retirements should be reported in columns (c) or (d) as appropriate.
3. If necessary, classify Account 106 according to prescribed accounts, on an estimated basis, and include in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the completed construction properly classified in column (c).
4. If there is a significant amount of plant retirements, which have not been classified by plant account at year end, a tentative distribution of such retirements, on an estimated basis, should be included in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the retired plant is properly classified in column (d).

Account (a)	Balance First of Year (b)	Additions During Year (c)	Retirements During Year (d)	
INTANGIBLE PLANT				
Organization (301)	0			1
Franchises and Consents (302)	4,250,029			2
Miscellaneous Intangible Plant (303)	3,988,698	272,281		3
Total Intangible Plant	**8,238,727**	**272,281**	**0**	
STEAM PRODUCTION PLANT				
Land and Land Rights (310)	74,018			4
Structures and Improvements (311)	13,796,396	11,429		5
Boiler Plant Equipment (312)	71,619,514	1,260,756	443,799	6
Engines and Engine-Driven Generators (313)	0			7
Turbogenerator Units (314)	9,073,164	35,468	152,877	8
Accessory Electric Equipment (315)	6,633,642	85,887		9
Miscellaneous Power Plant Equipment (316)	1,218,990	161,060		10
Asset Retirement Costs for Steam Production (317)	0			11
Total Steam Production Plant	**102,415,724**	**1,554,600**	**596,676**	
NUCLEAR PRODUCTION PLANT				
Land and Land Rights (320)	0			12
Structures and Improvements (321)	0			13
Reactor Plant Equipment (322)	0			14
Turbogenerator Units (323)	0			15
Accessory Electric Equipment (324)	0			16
Miscellaneous Power Plant Equipment (325)	0			17
Asset Retirement Costs for Nuclear Production (326)	0			18
Total Nuclear Production Plant	**0**	**0**	**0**	
HYDRAULIC PRODUCTION PLANT				
Land and Land Rights (330)	2,433,805			19
Structures and Improvements (331)	18,360,879	371,511		20
Reservoirs, Dams and Waterways (332)	128,511,832	71,083	357,414	21
Water Wheels, Turbines and Generators (333)	51,840,687	9,337,729	311,810	22
Accessory Electric Equipment (334)	27,430,313	190,424	146,752	23
Miscellaneous Power Plant Equipment (335)	4,097,481	1,541,908	3,854	24
Roads, Railroads and Bridges (336)	0			25
Asset Retirement Costs for Hydraulic Production (337)	0			26
Total Hydraulic Production Plant	**232,674,997**	**11,512,655**	**819,830**	

ELECTRIC UTILITY PLANT IN SERVICE (cont.)

5. Column (f) is used to report the reclassifications or transfers within utility plant accounts.
6. Upon final disposition of Account 102, classify the plant balances according to prescribed accounts and include in column (f). The amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., should be reported in column (e).
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount, submit supplementary information reporting subaccount plant detail conforming to the requirements of this schedule.
8. Leased plant recorded in Account 101.1 should be further classified to the prescribed plant accounts.
9. For each transaction recorded in Account 102, describe the plant purchased or sold, identify the counterparty and date of transaction.

Account (a)	Adjustments Increase or (Decrease) (e)	Transfers (f)	Balance End of Year (g)	
Organization (301)			**0**	**1**
Franchises and Consents (302)		142,692	**4,392,721**	**2**
Miscellaneous Intangible Plant (303)			**4,260,979**	**3**
	0	**142,692**	**8,653,700**	
Land and Land Rights (310)			**74,018**	**4**
Structures and Improvements (311)			**13,807,825**	**5**
Boiler Plant Equipment (312)			**72,436,471**	**6**
Engines and Engine-Driven Generators (313)			**0**	**7**
Turbogenerator Units (314)			**8,955,755**	**8**
Accessory Electric Equipment (315)			**6,719,529**	**9**
Miscellaneous Power Plant Equipment (316)			**1,380,050**	**10**
Asset Retirement Costs for Steam Production (317)			**0**	**11**
	0	**0**	**103,373,648**	
Land and Land Rights (320)			**0**	**12**
Structures and Improvements (321)			**0**	**13**
Reactor Plant Equipment (322)			**0**	**14**
Turbogenerator Units (323)			**0**	**15**
Accessory Electric Equipment (324)			**0**	**16**
Miscellaneous Power Plant Equipment (325)			**0**	**17**
Asset Retirement Costs for Nuclear Production (326)			**0**	**18**
	0	**0**	**0**	
Land and Land Rights (330)			**2,433,805**	**19**
Structures and Improvements (331)		(35,207)	**18,697,183**	**20**
Reservoirs, Dams and Waterways (332)		(119,999)	**128,105,502**	**21**
Water Wheels, Turbines and Generators (333)		15	**60,866,621**	**22**
Accessory Electric Equipment (334)		12,499	**27,486,484**	**23**
Miscellaneous Power Plant Equipment (335)			**5,635,535**	**24**
Roads, Railroads and Bridges (336)			**0**	**25**
Asset Retirement Costs for Hydraulic Production (337)			**0**	**26**
	0	**(142,692)**	**243,225,130**	

ELECTRIC UTILITY PLANT IN SERVICE

1. Report below the original cost of utility plant in service according to the prescribed accounts.
2. Corrections to prior entries for plant additions and retirements should be reported in columns (c) or (d) as appropriate.
3. If necessary, classify Account 106 according to prescribed accounts, on an estimated basis, and include in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the completed construction properly classified in column (c).
4. If there is a significant amount of plant retirements, which have not been classified by plant account at year end, a tentative distribution of such retirements, on an estimated basis, should be included in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the retired plant is properly classified in column (d).

Account (a)	Balance First of Year (b)	Additions During Year (c)	Retirements During Year (d)		
OTHER PRODUCTION PLANT					
Land and Land Rights (340)	192,347				**27**
Structures and Improvements (341)	2,472,367		39,676		**28**
Fuel Holders, Producers and Accessories (342)	3,236,893				**29**
Prime Movers (343)	33,535,719	17,094	315,099		**30**
Generators (344)	20,213,879	42,288	162,129		**31**
Accessory Electric Equipment (345)	6,771,922	63,269	16,234		**32**
Miscellaneous Power Plant Equipment (346)	1,483,468	35,793			**33**
Asset Retirement Costs for Other Production (347)	0				**34**
Total Other Production Plant	**67,906,595**	**158,444**	**533,138**		
TRANSMISSION PLANT					
Land and Land Rights (350)	13,321,147	1,103,704			**35**
Structures and Improvements (352)	9,349,041	(159,306)		*	**36**
Station Equipment (353)	132,486,149	4,619,333	164,872		**37**
Towers and Fixtures (354)	2,988,240		466		**38**
Poles and Fixtures (355)	140,906,183	4,654,128	1,475,647		**39**
Overhead Conductors and Devices (356)	97,581,965	1,853,204	671,486		**40**
Underground Conduit (357)	65,524				**41**
Underground Conductors and Devices (358)	228,510				**42**
Roads and Trails (359)	26,067				**43**
Asset Retirement Costs for Transmission Plant (359.1)	0				**44**
Total Transmission Plant	**396,952,826**	**12,071,063**	**2,312,471**		
DISTRIBUTION PLANT					
Land and Land Rights (360)	1,262,910	68,363			**45**
Structures and Improvements (361)	3,987,060	280,486	49,741		**46**
Station Equipment (362)	94,311,486	4,195,858	493,251		**47**
Storage Battery Equipment (363)	0				**48**
Poles, Towers and Fixtures (364)	86,152,016	2,927,712	138,688		**49**
Overhead Conductors and Devices (365)	95,745,880	3,172,818	772,912		**50**
Underground Conduit (366)	14,069,358	476,043	9,365		**51**
Underground Conductors and Devices (367)	74,349,319	4,897,745	273,925		**52**
Line Transformers (368)	88,470,966	3,915,585	405,827		**53**
Services (369)	78,681,214	2,391,413	172,074		**54**
Meters (370)	24,377,448	3,535,133	12,849		**55**
Installations on Customers' Premises (371)	5,193,516	42,782	149,655		**56**
Leased Property on Customers' Premises (372)	0				**57**
Street Lighting and Signal Systems (373)	7,718,602	285,521	55,881		**58**

ELECTRIC UTILITY PLANT IN SERVICE (cont.)

5. Column (f) is used to report the reclassifications or transfers within utility plant accounts.
6. Upon final disposition of Account 102, classify the plant balances according to prescribed accounts and include in column (f). The amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., should be reported in column (e).
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount, submit supplementary information reporting subaccount plant detail conforming to the requirements of this schedule.
8. Leased plant recorded in Account 101.1 should be further classified to the prescribed plant accounts.
9. For each transaction recorded in Account 102, describe the plant purchased or sold, identify the counterparty and date of transaction.

Account (a)	Adjustments Increase or (Decrease) (e)	Transfers (f)	Balance End of Year (g)		
Land and Land Rights (340)			**192,347**		**27**
Structures and Improvements (341)			**2,432,691**		**28**
Fuel Holders, Producers and Accessories (342)		48,645	**3,285,538**		**29**
Prime Movers (343)		(48,645)	**33,189,069**		**30**
Generators (344)			**20,094,038**		**31**
Accessory Electric Equipment (345)		39,566	**6,858,523**		**32**
Miscellaneous Power Plant Equipment (346)		(39,566)	**1,479,695**		**33**
Asset Retirement Costs for Other Production (347)			**0**		**34**
	0	**0**	**67,531,901**		
Land and Land Rights (350)		1,652	**14,426,503**		**35**
Structures and Improvements (352)			**9,189,735**	*	**36**
Station Equipment (353)		1,034,779	**137,975,389**		**37**
Towers and Fixtures (354)			**2,987,774**		**38**
Poles and Fixtures (355)		(9,610)	**144,075,054**		**39**
Overhead Conductors and Devices (356)		7,958	**98,771,641**		**40**
Underground Conduit (357)			**65,524**		**41**
Underground Conductors and Devices (358)			**228,510**		**42**
Roads and Trails (359)			**26,067**		**43**
Asset Retirement Costs for Transmission Plant (359.1)			**0**		**44**
	0	**1,034,779**	**407,746,197**		
Land and Land Rights (360)		0	**1,331,273**		**45**
Structures and Improvements (361)		665,555	**4,883,360**		**46**
Station Equipment (362)		(1,700,334)	**96,313,759**		**47**
Storage Battery Equipment (363)			**0**		**48**
Poles, Towers and Fixtures (364)			**88,941,040**		**49**
Overhead Conductors and Devices (365)			**98,145,786**		**50**
Underground Conduit (366)			**14,536,036**		**51**
Underground Conductors and Devices (367)			**78,973,139**		**52**
Line Transformers (368)			**91,980,724**		**53**
Services (369)			**80,900,553**		**54**
Meters (370)			**27,899,732**		**55**
Installations on Customers' Premises (371)		(70,162)	**5,016,481**		**56**
Leased Property on Customers' Premises (372)			**0**		**57**
Street Lighting and Signal Systems (373)		70,162	**8,018,404**		**58**

ELECTRIC UTILITY PLANT IN SERVICE

1. Report below the original cost of utility plant in service according to the prescribed accounts.
2. Corrections to prior entries for plant additions and retirements should be reported in columns (c) or (d) as appropriate.
3. If necessary, classify Account 106 according to prescribed accounts, on an estimated basis, and include in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the completed construction properly classified in column (c).
4. If there is a significant amount of plant retirements, which have not been classified by plant account at year end, a tentative distribution of such retirements, on an estimated basis, should be included in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the retired plant is properly classified in column (d).

Account (a)	Balance First of Year (b)	Additions During Year (c)	Retirements During Year (d)		
DISTRIBUTION PLANT					
Asset Retirement Costs for Distribution Plant (374)	18,447	(4,967)		*	59
Total Distribution Plant	**574,338,222**	**26,184,492**	**2,534,168**		
GENERAL PLANT					
Land and Land Rights (389)	166,403				60
Structures and Improvements (390)	7,537,489	166,868			61
Office Furniture and Equipment (391)	2,602,446	1,438,595	54,072		62
Transportation Equipment (392)	10,748,916	2,246,497			63
Stores Equipment (393)	136,653				64
Tools, Shop and Garage Equipment (394)	7,708,888	830,226	725		65
Laboratory Equipment (395)	2,889,504		687		66
Power Operated Equipment (396)	3,305,781	429,861			67
Communication Equipment (397)	9,667,679	3,048,337	599,419		68
Miscellaneous Equipment (398)	17,731				69
Other Tangible Property (399)	0				70
Asset Retirement Costs for General Plant (399.1)	0				71
Total General Plant	**44,781,490**	**8,160,384**	**654,903**		
Total for Accounts 101 and 106	**1,427,308,581**	**59,913,919**	**7,451,186**		
Electric Plant Purchased (102)	0				72
(Less) Electric Plant Sold (102)	0				73
Experimental Plant Unclassified (103)	0				74
Total utility plant in service	**1,427,308,581**	**59,913,919**	**7,451,186**		

ELECTRIC UTILITY PLANT IN SERVICE (cont.)

5. Column (f) is used to report the reclassifications or transfers within utility plant accounts.
6. Upon final disposition of Account 102, classify the plant balances according to prescribed accounts and include in column (f). The amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., should be reported in column (e).
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount, submit supplementary information reporting subaccount plant detail conforming to the requirements of this schedule.
8. Leased plant recorded in Account 101.1 should be further classified to the prescribed plant accounts.
9. For each transaction recorded in Account 102, describe the plant purchased or sold, identify the counterparty and date of transaction.

Account (a)	Adjustments Increase or (Decrease) (e)	Transfers (f)	Balance End of Year (g)		
Asset Retirement Costs for Distribution Plant (374)			13,480	*	59
	0	(1,034,779)	596,953,767		
Land and Land Rights (389)			166,403		60
Structures and Improvements (390)			7,704,357		61
Office Furniture and Equipment (391)			3,986,969		62
Transportation Equipment (392)			12,995,413		63
Stores Equipment (393)			136,653		64
Tools, Shop and Garage Equipment (394)			8,538,389		65
Laboratory Equipment (395)			2,888,817		66
Power Operated Equipment (396)			3,735,642		67
Communication Equipment (397)			12,116,597		68
Miscellaneous Equipment (398)			17,731		69
Other Tangible Property (399)			0		70
Asset Retirement Costs for General Plant (399.1)			0		71
	0	0	52,286,971		
	0	0	1,479,771,314		
Electric Plant Purchased (102)			0		72
(Less) Electric Plant Sold (102)			0		73
Experimental Plant Unclassified (103)			0		74
	0	0	1,479,771,314		

ELECTRIC UTILITY PLANT IN SERVICE

Electric Utility Plant in Service (Page E-12)

General footnotes

36. Negative additions due to 106 reclass to different 101 plant account.
59. Negative additions due to 106 reclass to different 101 plant account.

ELECTRIC UTILITY PLANT IN SERVICE (cont.)

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ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (d)	Accruals During Year: Additional Amount (e)	
INTANGIBLE PLANT					
Organization (301)	0				1
Franchises and Consents (302)	0				2
Miscellaneous Intangible Plant (303)	2,120,309	Various		732,844	3
Total Intangible Plant	**2,120,309**		**0**	**732,844**	
STEAM PRODUCTION PLANT					
Land and Land Rights (310)	0				4
Structures and Improvements (311)	10,857,121	2.310%	319,458		5
Boiler Plant Equipment (312)	45,634,964	3.030%	2,184,511		6
Engines and Engine-Driven Generators (313)	0				7
Turbogenerator Units (314)	6,467,109	3.000%	270,097		8
Accessory Electric Equipment (315)	4,426,222	3.450%	230,574		9
Miscellaneous Power Plant Equipment (316)	665,830	3.500%	45,450		10
Asset Retirement Costs for Steam Production (317)	0				11
Total Steam Production Plant	**68,051,246**		**3,050,090**	**0**	
NUCLEAR PRODUCTION PLANT					
Land and Land Rights (320)	0				12
Structures and Improvements (321)	0				13
Reactor Plant Equipment (322)	0				14
Turbogenerator Units (323)	0				15
Accessory Electric Equipment (324)	0				16
Miscellaneous Power Plant Equipment (325)	0				17
Asset Retirement Costs for Nuclear Production (326)	0				18
Total Nuclear Production Plant	**0**		**0**	**0**	
HYDRAULIC PRODUCTION PLANT					
Land and Land Rights (330)	(1)	Various	1		19
Structures and Improvements (331)	8,484,044	2.670%	495,638		20
Reservoirs, Dams and Waterways (332)	67,858,743	2.650%	3,398,458	*	21
Water Wheels, Turbines and Generators (333)	17,927,471	3.010%	1,698,787	*	22
Accessory Electric Equipment (334)	11,300,948	2.780%	762,639	*	23
Miscellaneous Power Plant Equipment (335)	1,767,658	3.750%	182,603	*	24
Roads, Railroads and Bridges (336)	0				25
Asset Retirement Costs for Hydraulic Production (337)	0				26
Total Hydraulic Production Plant	**107,338,863**		**6,538,126**	**0**	
OTHER PRODUCTION PLANT					
Land and Land Rights (340)	0				27
Structures and Improvements (341)	2,373,086	1.260%	30,885		28
Fuel Holders, Producers and Accessories (342)	2,484,955	3.700%	120,599		29

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC (cont.)

Account (a)	Book Cost of Plant Retired (f)	Cost of Removal (g)	Salvage (h)	Adjustments Increase or (Decrease) (i)	Balance End of Year (j)		
301					**0**		**1**
302					**0**		**2**
303					**2,853,153**		**3**
	0	**0**	**0**	**0**	**2,853,153**		
310					**0**		**4**
311					**11,176,579**		**5**
312	443,799	70,927			**47,304,749**		**6**
313					**0**		**7**
314	152,877	26,988			**6,557,341**		**8**
315					**4,656,796**		**9**
316					**711,280**		**10**
317					**0**		**11**
	596,676	**97,915**	**0**	**0**	**70,406,745**		
320					**0**		**12**
321					**0**		**13**
322					**0**		**14**
323					**0**		**15**
324					**0**		**16**
325					**0**		**17**
326					**0**		**18**
	0	**0**	**0**	**0**	**0**		
330					**0**		**19**
331		32,914			**8,946,768**		**20**
332	357,414	78,834		95,383	**70,916,336**	*	**21**
333	311,810	211,529		109,309	**19,212,228**	*	**22**
334	146,752	132		141,025	**12,057,728**	*	**23**
335	3,854			3,180	**1,949,587**	*	**24**
336					**0**		**25**
337					**0**		**26**
	819,830	**323,409**	**0**	**348,897**	**113,082,647**		
340					**0**		**27**
341	39,676	2,012			**2,362,283**		**28**
342				31,109	**2,636,663**		**29**

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (d)	Accruals During Year: Additional Amount (e)	
OTHER PRODUCTION PLANT					
Prime Movers (343)	29,795,060	1.510%	503,698		30
Generators (344)	17,009,434	2.330%	469,041		31
Accessory Electric Equipment (345)	5,741,067	2.420%	165,126		32
Miscellaneous Power Plant Equipment (346)	875,190	7.030%	104,160		33
Asset Retirement Costs for Other Production (347)	0				34
Total Other Production Plant	**58,278,792**		**1,393,509**	**0**	
TRANSMISSION PLANT					
Land and Land Rights (350)	0				35
Structures and Improvements (352)	2,262,773	2.630%	248,683		36
Station Equipment (353)	63,719,213	3.290%	4,478,078		37
Towers and Fixtures (354)	2,651,275	2.300%	68,510		38
Poles and Fixtures (355)	41,676,098	3.000%	4,273,377		39
Overhead Conductors and Devices (356)	42,043,383	3.130%	3,076,490		40
Underground Conduit (357)	15,547	2.630%	1,724	*	41
Underground Conductors and Devices (358)	141,438	2.750%	6,284		42
Roads and Trails (359)	24,687	2.500%	652		43
Asset Retirement Costs for Transmission Plant (359.1)	0				44
Total Transmission Plant	**152,534,414**		**12,153,798**	**0**	
DISTRIBUTION PLANT					
Land and Land Rights (360)	0				45
Structures and Improvements (361)	1,008,370	2.630%	109,698		46
Station Equipment (362)	48,648,321	3.140%	2,963,098		47
Storage Battery Equipment (363)	0				48
Poles, Towers and Fixtures (364)	46,837,562	4.290%	3,761,350		49
Overhead Conductors and Devices (365)	41,809,681	3.430%	3,321,151		50
Underground Conduit (366)	5,538,540	2.630%	376,737		51
Underground Conductors and Devices (367)	19,955,894	2.570%	1,981,416		52
Line Transformers (368)	33,434,856	3.000%	2,703,076		53
Services (369)	49,689,680	4.330%	3,430,808		54
Meters (370)	9,482,986	4.550%	1,416,266		55
Installations on Customers' Premises (371)	4,889,316	7.920%	33,328		56
Leased Property on Customers' Premises (372)	0				57
Street Lighting and Signal Systems (373)	6,753,192	6.470%	501,740		58
Asset Retirement Costs for Distribution Plant (374)	8,419	2.140%	204		59
Total Distribution Plant	**268,056,817**		**20,598,872**	**0**	
GENERAL PLANT					
Land and Land Rights (389)	0				60
Structures and Improvements (390)	2,814,405	2.860%	216,189		61
Office Furniture and Equipment (391)	1,051,681	5.000%	139,019		62

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC (cont.)

Account (a)	Book Cost of Plant Retired (f)	Cost of Removal (g)	Salvage (h)	Adjustments Increase or (Decrease) (i)	Balance End of Year (j)		
343	315,099	193,797		(31,109)	**29,758,753**		**30**
344	162,129	16,642			**17,299,704**		**31**
345	16,234	3,240		19,198	**5,905,917**		**32**
346				(19,198)	**960,152**		**33**
347					**0**		**34**
	533,138	**215,691**	**0**	**0**	**58,923,472**		
350					**0**		**35**
352					**2,511,456**		**36**
353	164,872	82,309	63,096	46,910	**68,060,116**		**37**
354	466	(595)	15,587		**2,735,501**		**38**
355	1,475,647	343,442	282,061	(4,310)	**44,408,137**		**39**
356	671,486	155,467	505,374	4,310	**44,802,604**		**40**
357					**17,271**	*	**41**
358					**147,722**		**42**
359					**25,339**		**43**
359.1					**0**		**44**
	2,312,471	**580,623**	**866,118**	**46,910**	**162,708,146**		
360					**0**		**45**
361	49,741			44,516	**1,112,843**		**46**
362	493,251	295,756	2,073	(91,426)	**50,733,059**		**47**
363					**0**		**48**
364	138,688	627,744	468,820		**50,301,300**		**49**
365	772,912	424,645	530,564		**44,463,839**		**50**
366	9,365	11,437	33,813		**5,928,288**		**51**
367	273,925	32,988	84,693		**21,715,090**		**52**
368	405,827	701	3,781		**35,735,185**		**53**
369	172,074	205,972	24,826		**52,767,268**		**54**
370	12,849				**10,886,403**		**55**
371	149,655				**4,772,989**		**56**
372					**0**		**57**
373	55,881	134,374	38,746		**7,103,423**		**58**
374					**8,623**		**59**
	2,534,168	**1,733,617**	**1,187,316**	**(46,910)**	**285,528,310**		
389					**0**		**60**
390					**3,030,594**		**61**
391	54,072				**1,136,628**		**62**

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (d)	Accruals During Year: Additional Amount (e)	
GENERAL PLANT					
Transportation Equipment (392)	3,888,385	Various	1,139,580		63
Stores Equipment (393)	127,840	5.000%	753		64
Tools, Shop and Garage Equipment (394)	3,686,238	5.000%	407,894		65
Laboratory Equipment (395)	2,114,337	5.000%	144,474		66
Power Operated Equipment (396)	1,430,236	Various	257,854		67
Communication Equipment (397)	5,885,983	Various	446,079		68
Miscellaneous Equipment (398)	15,223	5.000%	117		69
Other Tangible Property (399)	0	Various			70
Asset Retirement Costs for General Plant (399.1)	0				71
Retirement Work in Progress	(2,887,047)	Various			* 72
Total General Plant	**18,127,281**		**2,751,959**	**0**	
Electric Plant Purchased (102)	0				73
(Less) Electric Plant Sold (102)	0				74
Experimental Plant Unclassified (103)	0				75
Total accum. prov. for depreciation	**674,507,722**		**46,486,354**	**732,844**	

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC (cont.)

Account (a)	Book Cost of Plant Retired (f)	Cost of Removal (g)	Salvage (h)	Adjustments Increase or (Decrease) (i)	Balance End of Year (j)		
392					**5,027,965**		**63**
393					**128,593**		**64**
394	725				**4,093,407**		**65**
395	687				**2,258,124**		**66**
396		(229)			**1,688,319**		**67**
397	599,419				**5,732,643**		**68**
398					**15,340**		**69**
399					**0**		**70**
399.1					**0**		**71**
RWIP		1,049,499	(773,521)		**(4,710,067)**	*	**72**
	654,903	**1,049,270**	**(773,521)**	**0**	**18,401,546**		
102					**0**		**73**
102b					**0**		**74**
103					**0**		**75**
	7,451,186	**4,000,525**	**1,279,913**	**348,897**	**711,904,019**		

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC

Accumulated Provision for Depreciation - Electric (Page E-14)

General footnotes

21. Book cost of plant retirements on this page defaults in from page E12. The plant retirement amount includes 95,383 of plant that is amortized to account 111.

22. Book cost of plant retirements on this page defaults in from page E12. The plant retirement amount includes 109,309 of plant that is amortized to account 111.

23. Book cost of plant retirements on this page defaults in from page E12. The plant retirement amount includes 141,025 of plant that is amortized to account 111.

24. Book cost of plant retirements on this page defaults in from page E12. The plant retirement amount includes 3,180 of plant that is amortized to account 111.

Balance End of Year includes (2,887,047) of electric retirement work in progress.

ACCUMULATED PROVISION FOR DEPRECIATION - ELECTRIC (cont.)

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Report data for plant in service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, sand nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as shown on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Item (a)	Plant Name: Bay Front (b)			Plant Name: Flambeau Station (c)			
Kind of Plant (Internal Comb, Gas Turb, Nuclear)			Steam			Gas Turbine	1
Type of Constr (Conventional, Outdoor, Boiler, etc.)			Conventional			Conventional	2
Year Originally Constructed			1917			1969	3
Year Last Unit was Installed			1958			1969	4
Total Installed Cap (Max Gen Name Plate Ratings-MW)			67.20			16.30	5
Net Peak Demand on Plant - MW (60 minutes)			72			8	6
Plant Hours Connected to Load			8,713			6,783	7
Net Continuous Plant Capability (Megawatts)			82			20	8
When Not Limited by Condenser Water			82			20	9
When Limited by Condenser Water			73			13	10
Average Number of Employees			33			1	11
Net generation, Exclusive of Plant Use - KWh (000's)			293,243,000			27,000	12
Cost of Plant: Land and Land Rights			67,165			9,798	13
Structures and Improvements			7,064,446			395,093	14
Equipment Costs			50,197,702			4,139,232	15
Asset Retirement Costs			0			0	16
Total Cost			**57,329,313**			**4,544,123**	17
Cost per KW of Installed Capacity (line 17/5) Including			853			279	18
Production Expenses: Oper, Supv, & Engr			27,965			760	19
Fuel			13,572,801			35,695	20
Coolants and Water (Nuclear Plants Only)			0			0	21
Steam Expenses			1,089,687			0	22
Steam From Other Sources			0			0	23
Steam Transferred (Cr)			0			0	24
Electric Expenses			603,886			19,708	25
Misc Steam (or Nuclear) Power Expenses			724,825			38,219	26
Rents			211,867			8,472	27
Allowances			466,553			0	28
Maintenance Supervision and Engineering			17,130			0	29
Maintenance of Structures			355,902			3,216	30
Maintenance of Boiler (or reactor) Plant			831,981			0	31
Maintenance of Electric Plant			135,089			38,035	32
Maintenance of Misc Steam (or Nuclear) Plant			318,227			10,958	33
Total Production Expense			**18,355,913**			**155,063**	34
Expenses per Net KWh			**0.0626**			**5.7431**	35
Fuel Kind (Coal, Gas, Oil, or Nuclear)	WOOD	COAL	GAS	OIL	GAS		36
Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	TON	TON	MCF	BARREL	MCF		37
Quantity (Units) of Fuel Burned	255,991	96,496	181,596	12	6,176		38
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	5,018	8,765	1,000	134,231	1,000		39
Avg Cost of Fuel/Unit, as Delvd f.o.b. during year	27.300	51.600	4.810	59.350	5.660		40
Average Cost of Fuel per Unit Burned	27.300	60.250	4.810	59.350	5.660		41
Average Cost of Fuel Burned per Million BTU	2.720	3.440	4.810	10.530	5.660		42
Average Cost of Fuel Burned per KWh Net Gen	0.000	0.050	0.000	0.000	1.270		43
Average BTU per KWh Net Generation	0.000	15,149.080	0.000	0.000	223,064.290		44
Footnotes							45

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (cont.)

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and other expenses classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

	Plant Name: French Island (d)	**Plant Name: French Island (e)**	**Plant Name: Wheaton (f)**	
	Gas Turbine	Steam	Gas Turbine	**1**
	Heated Individually	Conventional	Heated Individually	**2**
	1973	1940	1973	**3**
	1974	1948	1974	**4**
	157.60	30.40	300.30	**5**
	68	18	212	**6**
	51	5,539	242	**7**
	200	32	456	**8**
	200	32	456	**9**
	147	29	353	**10**
	0	28	7	**11**
	268,000	63,660,000	10,835,000	**12**
	0	6,853	182,549	**13**
	501,383	6,743,379	1,536,215	**14**
	17,241,412	39,294,103	42,534,880	**15**
	0	0	0	**16**
	17,742,795	**46,044,335**	**44,253,644**	**17**
	113	1,515	147	**18**
	23,060	247,215	95,963	**19**
	370,002	2,826,363	1,509,017	**20**
	0	0	0	**21**
	0	507,535	0	**22**
	0	0	0	**23**
	0	0	0	**24**
	60,494	208,875	202,289	**25**
	30,246	431,543	308,703	**26**
	40,344	124,168	64,681	**27**
	739	0	(15,101)	**28**
	1,780	2,534	6,118	**29**
	23,180	135,597	216,304	**30**
	0	1,171,477	0	**31**
	2,096,406	24,549	427,127	**32**
	0	439,507	7,543	**33**
	2,646,251	**6,119,363**	**2,822,644**	**34**
	9.8741	**0.0961**	**0.2605**	**35**

	(d)			(e)			(f)			
	OIL			WOOD	RDF	GAS	GAS	OIL		**36**
	BARREL			TON	TON	MCF	MCF	BARREL		**37**
	3,813			56,549	49,931	2,790	165,053	8,206		**38**
	139,535			6,561	5,581	1,013	1,004	153,137		**39**
	96.790			27.140	11.550	6.200	3.790	107.570		**40**
	96.790			40.980	11.550	6.200	3.790	107.570		**41**
	16.520			3.120	1.030	6.120	3.780	16.720		**42**
	1.380			0.000	0.050	0.000	0.000	0.140		**43**
	83,374.220			0.000	20,455.200	0.000	0.000	20,163.700		**44**
										45

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

Steam-Electric Generating Plant Statistics (Large Plants) (Page E-16)

General footnotes

The "Average Heat Content of Fuel Burned" is calculated as follows:

Coal: Btu/pound
Oil: Btu/gallon
Gas: Btu/cubic ft.

Bayfront Wood totals include railroad ties, tires and pet coke

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (cont.)

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HYDROELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (nameplate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Item (a)	FERC Licensed Project No. 2440 Name: Chippewa Falls (b)	FERC Licensed Project No. 2639 Name: Cornell (c)	
Kind of Plant (Run-of-River or Storage)	Peaking	Peaking	1
Plant Construction Type (Conventional or Outdoor)	Conventional	Conventional	2
Year Originally Constructed	1928	1976	3
Year Last Unit was Installed	1928	1977	4
Total Installed Cap (Gen Name Plate Ratings-MW)	21.60	35.30	5
Net Peak Demand on Plant - MW (60 minutes)	0	0	6
Plant Hours Connected to Load	0	0	7
Net Continuous Plant Capability (Megawatts)			8
(a) Under Most Favorable Oper Conditions	23	33	9
(b) Under the Most Adverse Oper Conditions	23	33	10
Average Number of Employees	0	1	11
Net generation, Exclusive of Plant Use - KWh	38,839,000	43,480,000	12
Cost of Plant			13
Land and Land Rights	112,909	51,432	14
Structures and Improvements	513,954	2,438,365	15
Reservoirs, Dams and Waterways	3,174,177	13,407,976	16
Equipment Costs	9,388,363	5,003,554	17
Roads, Railroads and Bridges	0	0	18
Asset Retirement Costs	0	0	19
Total Cost	**13,189,403**	**20,901,327**	20
Cost per KW of Installed Capacity (line 20/5)	**610.6205**	**592.1056**	21
Production Expenses			22
Operation Supervision and Engineering	0	168,967	23
Water for Power	58,864	77,571	24
Hydraulic Expenses	0	61,886	25
Electric Expenses	39,623	0	26
Misc Hydraulic Power Generation Expense	128,807	213,785	27
Rents	21,743	33,583	28
Maintenance Supervision and Engineering	47,164	68,996	29
Maintenance of Structures	13,793	8,316	30
Maint. of Reservoirs, Dams and Waterways	180,581	20,703	31
Maintenance of Electric Plant	16,127	128,642	32
Maintenance of Misc Hydraulic Plant	33,201	7,758	33
Total Production Expense	**539,903**	**790,207**	34
Expenses per Net KWh	**0.0139**	**0.0182**	35
Footnotes			36

HYDROELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (cont.)

	FERC Licensed Project No. 1982 Name: Holcombe (d)	FERC Licensed Project No. 2491 Name: Jim Falls (e)	FERC Licensed Project No. 0 Name: St. Croix Falls (f)	
	Peaking	Peaking	Peaking	1
	Conventional	Conventional	Conventional	2
	1950	1923	1905	3
	1950	1988	1911	4
	33.75	50.20	24.80	5
	0	0	0	6
	0	0	0	7
				8
	35	57	26	9
	35	57	26	10
	1	1	5	11
	48,745,000	59,461,000	96,624,000	12
				13
	230,831	851,120	85,185	14
	857,378	9,689,885	855,935	15
	7,048,534	69,534,015	1,542,109	16
	3,746,534	26,507,716	7,897,357	17
	0	0	0	18
	0	0	0	19
	11,883,277	**106,582,736**	**10,380,586**	20
	352.0971	**2,123.1621**	**418.5720**	21
				22
	0	0	3,667	23
	77,644	101,851	0	24
	2,066	108	0	25
	412	97,646	106,180	26
	190,887	300,910	142,865	27
	30,815	23,722	45,991	28
	53,572	72,349	58,192	29
	5,083	15,593	14,485	30
	51,208	69,190	24,619	31
	178,827	100,420	261,560	32
	22,967	46,769	8,793	33
	613,481	**828,558**	**666,352**	34
	0.0126	**0.0139**	**0.0069**	35
				36

HYDROELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (nameplate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Item (a)	FERC Licensed Project No. 2567 Name: Wissota (b)	(c)	
Kind of Plant (Run-of-River or Storage)	Peaking		1
Plant Construction Type (Conventional or Outdoor)	Conventional		2
Year Originally Constructed	1917		3
Year Last Unit was Installed	1917		4
Total Installed Cap (Gen Name Plate Ratings-MW)	36.00		5
Net Peak Demand on Plant - MW (60 minutes)	0		6
Plant Hours Connected to Load	0		7
Net Continuous Plant Capability (Megawatts)			8
(a) Under Most Favorable Oper Conditions	37		9
(b) Under the Most Adverse Oper Conditions	37		10
Average Number of Employees	7		11
Net generation, Exclusive of Plant Use - KWh	75,598,000		12
Cost of Plant			13
Land and Land Rights	379,040		14
Structures and Improvements	1,405,550		15
Reservoirs, Dams and Waterways	14,677,273		16
Equipment Costs	4,888,014		17
Roads, Railroads and Bridges	0		18
Asset Retirement Costs	0		19
Total Cost	**21,349,877**		20
Cost per KW of Installed Capacity (line 20/5)	**593.0521**		21
Production Expenses			22
Operation Supervision and Engineering	0		23
Water for Power	106,678		24
Hydraulic Expenses	922		25
Electric Expenses	526,465		26
Misc Hydraulic Power Generation Expense	372,064		27
Rents	74,056		28
Maintenance Supervision and Engineering	112,435		29
Maintenance of Structures	21,114		30
Maint. of Reservoirs, Dams and Waterways	29,665		31
Maintenance of Electric Plant	37,667		32
Maintenance of Misc Hydraulic Plant	6,537		33
Total Production Expense	**1,287,603**		34
Expenses per Net KWh	**0.0170**		35
Footnotes			36

HYDROELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS) (cont.)

	(d)	(e)	(f)	
				1
				2
				3
				4
				5
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				36

GENERATING PLANT STATISTICS (SMALL PLANTS)

1. Small generating plants are steam plants of less than 25,000 Kw, internal combustion and gas-turbine plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Plant Name (a)	Year Originally Constructed (b)	Installed Capacity Name Plate Rating (in MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	
Apple River	1901	2.25	3.2	8,633,000	2,551,386	1
Cedar Falls	1910	6.00	7.3	22,489,000	4,989,876	2
Menomonie	1958	5.40	5.4	16,071,000	4,232,439	3
Riverdale	1905	0.50	0.6	1,965,000	812,357	4
Trego	1926	1.20	1.5	5,446,000	1,292,349	5
Big Falls	1922	7.78	7.5	20,570,000	3,296,144	6
Hayward	1910	0.17	0.2	1,325,000	250,780	7
Ladysmith	1941	3.40	2.9	4,700,000	5,267,937	8
Saxon Falls	1912	1.55	1.5	9,210,000	1,329,066	9
Superior Falls	1917	1.85	1.9	9,888,000	1,840,858	10
Thornapple	1927	1.40	1.7	5,333,000	2,697,178	11
White River	1907	1.00	0.8	3,308,000	1,290,186	12
Eau Claire Dells	1907	8.40	12.3	27,399,000	28,725,598	13

GENERATING PLANT STATISTICS (SMALL PLANTS) (cont.)

Plant Cost (Including Asset Retirement Costs) Per MW (g)	Operation Excluding Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million BTU) (l)	
		Fuel (i)	Maintenance (j)			
1,133,949	47,154		156,247			1
831,646	317,615		57,438			2
783,785	107,741		117,357			3
1,624,714	19,743		131,514			4
1,076,958	95,668		60,492			5
423,669	313,235		128,278			6
1,475,176	29,702		28,349			7
1,549,393	118,370		188,006			8
857,462	74,763		24,697			9
995,058	142,019		41,953			10
1,926,556	55,416		47,457			11
1,290,186	120,522		250,584			12
3,419,714	779,792		352,584			13

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Particulars (a)		MegaWatt Hours (b)	
Source of Energy			
Generation (excluding Station Use):			
Steam		356,903	1
Combined Cycle		0	2
Combustion Turbine		11,130	3
Nuclear		0	4
Hydro-Conventional		499,084	5
Internal Combustion		0	6
Wind		0	7
Other		0	8
Net Generation		**867,117**	9
Purchases		6,643,933	10
Power Exchanges:	Received	0	11
	Delivered	0	12
	Net Exchanges	**0**	13
Transmission for Others (Wheeling):	Received	0	14
	Delivered	0	15
	Net Transmission for Other	**0**	16
Transmission by Others Losses			17
Total Source of Energy		**7,511,050**	18
			19
Disposition of Energy			20
Sales to Ultimate Consumers (Including Interdepartmental Sales)		6,305,298	21
Requirements Sales For Resale		530,856	22
Non-Requirements Sales For Resale		0	23
Energy Furnished Without Charge			24
Energy Used by the Company (Electric Dept. Only, Excluding Station Use)		6,809	25
Total Energy Losses		668,087	26
Total Disposition of Energy		**7,511,050**	27

MONTHLY PEAKS AND OUTPUT

1. Report hereunder the information called for pertaining to simultaneous peaks established monthly (in Megawatt-hours).
2. Monthly peak col. (b) should be respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) of emergency power to another system.
3. State type of monthly peak reading (instantaneous (0), 15, 30, or 60 minutes integrated).
4. Monthly output should be the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling.
5. If the utility has two or more power systems not physically connected, the information called for below should be furnished for each system.
6. Report Time Ending col. (e) in military time.

Month (a)		Monthly Peak: MW (b)	Day of Week (c)	Date (MM/DD/YYYY) (d)	Time Ending (HH:MM) (e)	Type of Reading (0, 15, 30, 60) (f)	Monthly Output (MWh) (g)	
January	01	720,364	Thursday	01/15/2009	19:00	60	1,183	1
February	02	614,137	Wednesday	02/04/2009	08:00	60	1,153	2
March	03	636,464	Thursday	03/12/2009	08:00	60	1,110	3
April	04	580,446	Monday	04/06/2009	11:00	60	1,016	4
May	05	572,351	Wednesday	05/20/2009	13:00	60	1,028	5
June	06	621,044	Tuesday	06/23/2009	15:00	60	1,404	6
July	07	627,508	Friday	07/10/2009	14:00	60	1,125	7
August	08	651,450	Friday	08/14/2009	15:00	60	1,269	8
September	09	606,604	Tuesday	09/15/2009	15:00	60	1,116	9
October	10	608,497	Friday	10/23/2009	13:00	60	1,023	10
November	11	588,706	Monday	11/30/2009	18:00	60	1,027	11
December	12	683,479	Thursday	12/10/2009	18:00	60	1,163	12
	Totals:						**13,617**	

System Name: Northern States Power Co (a Wisconsin corporation)

GENERATION SUMMARY WORKSHEET

Plant Name (a)	Unit ID (b)	Generator Nameplate Capacity (MW) (c)	Type of Prime Mover (d)	Summer Capability (MW) (e)	Winter Capability (MW) (f)	Net Generation (MWh) (g)		
Located in Wisconsin and operated by utility								
COAL								
Bayfront	4	20.00	ST	22.00	22.00	89,595.99	*	1
Bayfront	5	20.00	ST	22.00	22.00	93,139.85	*	2
Bayfront	6	27.20	ST	29.00	29.00	110,507.10	*	3
Bayfront MW Subtotal:		**67.20**		**73.00**	**73.00**	**293,242.94**		
COAL MW Subtotal:		**67.20**		**73.00**	**73.00**	**293,242.94**		
GAS								
Flambeau Station	1	16.32	GT	13.00	19.00	27.20		4
Flambeau Station MW Subtotal:		**16.32**		**13.00**	**19.00**	**27.20**		
Wheaton	1	48.50	GT	56.39	71.00	3,579.00		5
Wheaton	2	48.50	GT	64.99	71.40	3,331.00		6
Wheaton	3	48.50	GT	56.13	70.30	2,238.00		7
Wheaton	4	48.50	GT	55.81	70.30	1,825.00		8
Wheaton MW Subtotal:		**194.00**		**233.32**	**283.00**	**10,973.00**		
GAS MW Subtotal:		**210.32**		**246.32**	**302.00**	**11,000.20**		
NUCLEAR								
	NONE							9
		0.00		**0.00**	**0.00**	**0.00**		
NUCLEAR MW Subtotal:		**0.00**		**0.00**	**0.00**	**0.00**		
OIL								
French Island	3	78.80	GT	73.50	94.83	(294.70)		10
French Island	4	78.80	GT	73.20	94.83	562.30		11
French Island MW Subtotal:		**157.60**		**146.70**	**189.66**	**267.60**		
Wheaton	5	53.13	GT	59.65	79.80	82.00		12
Wheaton	6	53.13	GT	60.27	79.80	(220.00)		13
Wheaton MW Subtotal:		**106.26**		**119.92**	**159.60**	**(138.00)**		
OIL MW Subtotal:		**263.86**		**266.62**	**349.26**	**129.60**		
HYDRO								
Apple River	1	0.75	HY	0.97	0.97	2,597.00		14

GENERATION SUMMARY WORKSHEET (cont.)

Fuel Burned Primary Fuel (h)	Fuel Burned Secondary Fuel (i)	Fuel Burned Tertiary Fuel (j)	Primary Fuel Heating Value (BTUs Per Unit) (k)	Secondary Fuel Heating Value (BTUs Per Unit) (l)	Tertiary Fuel Heating Value (BTUs Per Unit) (m)		
Coal (Tons)	**Other**	**Gas (Mcf.)**					
96,496.00	255,991.00	181,596.00	8,765	5,018	1,000	*	1
n/a							
						*	2
						*	3
Gas (Mcf.)	**Oil (Bbls.)**						
6,176.00	12.00		1,000	134,231			4
Gas (Mcf.)	**Oil (Bbls.)**						
47,483.00	2,126.00		1,004	153,137			5
50,182.00	1,429.00		1,004	153,137			6
37,683.00	607.00		1,004	153,137			7
29,705.00	1,054.00		1,004	153,137			8
							9
Oil (Bbls.)	**Oil (Bbls.)**						
0.00							10
3,813.00			139,535				11
Oil (Bbls.)	**Oil (Bbls.)**						
1,591.00			153,137				12
1,399.00			153,137				13
							14

GENERATION SUMMARY WORKSHEET

Plant Name (a)	Unit ID (b)	Generator Nameplate Capacity (MW) (c)	Type of Prime Mover (d)	Summer Capability (MW) (e)	Winter Capability (MW) (f)	Net Generation (MWh) (g)	
Located in Wisconsin and operated by utility							
HYDRO							
Apple River	3	0.75	HY	1.11	1.11	2,487.00	15
Apple River	4	0.75	HY	1.11	1.11	3,549.00	16
Apple River MW Subtotal:		**2.25**		**3.19**	**3.19**	**8,633.00**	
Big Falls	1	2.64	HY	2.50	2.50	7,486.00	17
Big Falls	2	2.64	HY	2.50	2.50	10,313.00	18
Big Falls	3	2.50	HY	2.49	2.49	2,771.00	19
Big Falls MW Subtotal:		**7.78**		**7.49**	**7.49**	**20,570.00**	
Cedar Falls	1	2.00	HY	2.64	2.64	11,002.00	20
Cedar Falls	2	2.00	HY	2.28	2.28	4,989.00	21
Cedar Falls	3	2.00	HY	2.33	2.33	6,498.00	22
Cedar Falls MW Subtotal:		**6.00**		**7.25**	**7.25**	**22,489.00**	
Chippewa Falls	1	3.60	HY	3.79	3.79	8,758.00	23
Chippewa Falls	2	3.60	HY	4.01	4.01	3,434.00	24
Chippewa Falls	3	3.60	HY	3.89	3.89	2,971.00	25
Chippewa Falls	4	3.60	HY	3.89	3.89	10,463.00	26
Chippewa Falls	5	3.60	HY	3.88	3.88	10,415.00	27
Chippewa Falls	6	3.60	HY	4.01	4.01	2,798.00	28
Chippewa Falls MW Subtotal:		**21.60**		**23.47**	**23.47**	**38,839.00**	
Cornell	1	11.50	HY	10.33	10.33	9,439.00	29
Cornell	2	11.50	HY	10.69	10.69	19,419.00	30
Cornell	3	11.50	HY	11.43	11.43	10,753.00	31
Cornell	4	0.80	HY	0.73	0.73	3,869.00	32
Cornell MW Subtotal:		**35.30**		**33.18**	**33.18**	**43,480.00**	
Dells	1	2.00	HY	3.20	3.20	10,367.00	33
Dells	2	1.60	HY	2.50	2.50	8,214.00	34
Dells	3	1.60	HY	2.50	2.50	5,326.00	35
Dells	4	1.60	HY	2.50	2.50	1,480.00	36
Dells	5	1.60	HY	1.60	1.60	2,012.00	37
Dells MW Subtotal:		**8.40**		**12.30**	**12.30**	**27,399.00**	
Hayward	1	0.17	HY	0.20	0.20	1,325.00	38
Hayward MW Subtotal:		**0.17**		**0.20**	**0.20**	**1,325.00**	
Holcombe	1	11.25	HY	11.76	11.76	21,039.00	39
Holcombe	2	11.25	HY	11.75	11.75	16,946.00	40
Holcombe	3	11.25	HY	11.76	11.76	10,760.00	41
Holcombe MW Subtotal:		**33.75**		**35.27**	**35.27**	**48,745.00**	

GENERATION SUMMARY WORKSHEET (cont.)

Fuel Burned Primary Fuel (h)	Fuel Burned Secondary Fuel (i)	Fuel Burned Tertiary Fuel (j)	Primary Fuel Heating Value (BTUs Per Unit) (k)	Secondary Fuel Heating Value (BTUs Per Unit) (l)	Tertiary Fuel Heating Value (BTUs Per Unit) (m)	
						15
						16
						17
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GENERATION SUMMARY WORKSHEET

Plant Name (a)	Unit ID (b)	Generator Nameplate Capacity (MW) (c)	Type of Prime Mover (d)	Summer Capability (MW) (e)	Winter Capability (MW) (f)	Net Generation (MWh) (g)	
Located in Wisconsin and operated by utility							
HYDRO							
Jim Falls	HC1	24.80	HY	27.96	27.96	28,085.00	**42**
Jim Falls	HC2	24.80	HY	28.26	28.26	28,978.00	**43**
Jim Falls	MSF	0.60	HY	0.50	0.50	2,398.00	**44**
Jim Falls MW Subtotal:		**50.20**		**56.72**	**56.72**	**59,461.00**	
Ladysmith	1	0.90	HY	0.89	0.89	1,907.00	**45**
Ladysmith	2	0.90	HY	0.86	0.86	2,033.00	**46**
Ladysmith	3	1.60	HY	1.11	1.11	760.00	**47**
Ladysmith MW Subtotal:		**3.40**		**2.86**	**2.86**	**4,700.00**	
Menomonie	1	2.70	HY	2.66	2.66	9,397.00	**48**
Menomonie	2	2.70	HY	2.72	2.72	6,674.00	**49**
Menomonie MW Subtotal:		**5.40**		**5.38**	**5.38**	**16,071.00**	
Riverdale	1	0.25	HY	0.33	0.33	755.00	**50**
Riverdale	2	0.25	HY	0.30	0.30	1,210.00	**51**
Riverdale MW Subtotal:		**0.50**		**0.63**	**0.63**	**1,965.00**	
Saxon Falls	1	0.75	HY	0.70	0.55	3,484.00	**52**
Saxon Falls	2	0.80	HY	0.80	0.65	5,726.00	**53**
Saxon Falls MW Subtotal:		**1.55**		**1.50**	**1.20**	**9,210.00**	
St Croix Falls	1	2.50	HY	3.00	3.00	7,672.00	**54**
St Croix Falls	2	2.50	HY	3.00	3.00	8,302.00	**55**
St Croix Falls	3	2.50	HY	3.20	3.20	20,362.00	**56**
St Croix Falls	4	2.50	HY	3.20	3.20	17,903.00	**57**
St Croix Falls	5	3.40	HY	3.40	3.40	17,961.00	**58**
St Croix Falls	6	3.40	HY	3.30	3.30	8,926.00	**59**
St Croix Falls	7	4.00	HY	3.40	3.40	9,286.00	**60**
St Croix Falls	8	4.00	HY	3.20	3.20	6,212.00	**61**
St Croix Falls MW Subtotal:		**24.80**		**25.70**	**25.70**	**96,624.00**	
Superior Falls	1	0.95	HY	0.95	0.75	4,580.00	**62**
Superior Falls	2	0.90	HY	0.90	0.70	5,308.00	**63**
Superior Falls MW Subtotal:		**1.85**		**1.85**	**1.45**	**9,888.00**	
Thornapple	1	0.70	HY	0.81	0.81	2,684.00	**64**
Thornapple	2	0.70	HY	0.86	0.86	2,649.00	**65**
Thornapple MW Subtotal:		**1.40**		**1.67**	**1.67**	**5,333.00**	
Trego	1	0.70	HY	0.88	0.88	5,159.00	**66**

GENERATION SUMMARY WORKSHEET (cont.)

Fuel Burned Primary Fuel (h)	Fuel Burned Secondary Fuel (i)	Fuel Burned Tertiary Fuel (j)	Primary Fuel Heating Value (BTUs Per Unit) (k)	Secondary Fuel Heating Value (BTUs Per Unit) (l)	Tertiary Fuel Heating Value (BTUs Per Unit) (m)	
						42
						43
						44
						45
						46
						47
						48
						49
						50
						51
						52
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						60
						61
						62
						63
						64
						65
						66

GENERATION SUMMARY WORKSHEET

Plant Name (a)	Unit ID (b)	Generator Nameplate Capacity (MW) (c)	Type of Prime Mover (d)	Summer Capability (MW) (e)	Winter Capability (MW) (f)	Net Generation (MWh) (g)	
Located in Wisconsin and operated by utility							
HYDRO							
Trego	2	0.50	HY	0.61	0.61	287.00	**67**
Trego MW Subtotal:		**1.20**		**1.49**	**1.49**	**5,446.00**	
White River	1	0.50	HY	0.42	0.30	321.00	**68**
White River	2	0.50	HY	0.42	0.30	2,987.00	**69**
White River MW Subtotal:		**1.00**		**0.84**	**0.60**	**3,308.00**	
Wissota	1	6.00	HY	6.09	6.09	5,999.00	**70**
Wissota	2	6.00	HY	6.22	6.22	6,743.00	**71**
Wissota	3	6.00	HY	6.09	6.09	13,634.00	**72**
Wissota	4	6.00	HY	6.09	6.09	40,034.00	**73**
Wissota	5	6.00	HY	5.99	5.99	7,016.00	**74**
Wissota	6	6.00	HY	6.09	6.09	2,172.00	**75**
Wissota MW Subtotal:		**36.00**		**36.57**	**36.57**	**75,598.00**	
HYDRO MW Subtotal:		**242.55**		**257.56**	**256.62**	**499,084.00**	
WIND							
							76
		0.00		**0.00**	**0.00**	**0.00**	
WIND MW Subtotal:		**0.00**		**0.00**	**0.00**	**0.00**	
OTHER RENEWABLES (PHOTOVOLTAICS, FUEL CELLS)							
French Island	1	15.20	ST	15.00	15.00	35,606.43	* **77**
French Island	2	15.20	ST	14.00	14.00	28,053.57	* **78**
French Island MW Subtotal:		**30.40**		**29.00**	**29.00**	**63,660.00**	
OTHER RENEWABLES (PHOTOVOLTAICS, FUEL CELLS) MW Subtotal:		**30.40**		**29.00**	**29.00**	**63,660.00**	
DISTRIBUTED GENERATORS							
							79
		0.00		**0.00**	**0.00**	**0.00**	
DISTRIBUTED GENERATORS MW Subtotal:		**0.00**		**0.00**	**0.00**	**0.00**	
MW TOTAL:		**814.33**		**872.50**	**1,009.88**	**867,116.74**	

Located in Wisconsin and operated by utility

Total Generator Nameplate Capacity: **814.33** **Total Net Generation:** **867,116.74**

GENERATION SUMMARY WORKSHEET (cont.)

Fuel Burned Primary Fuel (h)	Fuel Burned Secondary Fuel (i)	Fuel Burned Tertiary Fuel (j)	Primary Fuel Heating Value (BTUs Per Unit) (k)	Secondary Fuel Heating Value (BTUs Per Unit) (l)	Tertiary Fuel Heating Value (BTUs Per Unit) (m)	
						67
						68
						69
						70
						71
						72
						73
						74
						75
						76
Other	**Other**	**Gas (Mcf.)**				
29,720.00	26,212.00	1,531.00	6,561	5,581	1,013	* 77
26,829.00	23,719.00	1,259.00	6,561	5,581	1,013	* 78
						79

GENERATION SUMMARY WORKSHEET

Generation Summary Worksheet (Page E-24)

General footnotes

Bayfront has a common steam header that feeds all three turbines. Fuel usage by turbine unit is not available. Numbers shown are for the total plant.

Bayfront Secondary Fuel Wood Tons

French Island Primary fuel is Wood Tons and Secondary fuel is RDF Tons.

GENERATION SUMMARY WORKSHEET (cont.)

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COAL CONTRACT INFORMATION - SPECIFICATION AND COSTS

Vendor Name/ Term of Agreement/ Plant Name (a) - (c)	Total Cost of Coal Delivered (d)	Total Units Delivered (2,000 lb. tons) (e)	Avg. Btu's per lb. of Coal Delivered (f)	Avg. Percent Moisture of Coal Delivered (g)	Avg. Percent Sulfur of Coal Delivered (h)	Avg. Percent Ash of Coal Delivered (i)		
C. Reiss / 05-15-2007 to 12-31-2010 Bay Front	290,937	70,105					*	1
Coal Sales, LLC / 01-01-2009 to 12-31-2010 Bay Front	1,449,624	88,916	8,733	27.61%	0.21%	4.57%		2
Kiewit Mine / 01-01-2007 to 12-31-2010 Bay Front	479,481	28,154	9,340	25.18%	0.43%	4.39%		3
Midwest Energy / 02-01-2007 to 12-31-2010 Bay Front	901,494	23,203					*	4
Midwest Energy / 02-01-2007 to 12-31-2010 Bay Front	849,368	23,341					*	5
Midwest Energy / 02-01-2007 to 12-31-2010 Bay Front	2,492,949	74,533					*	6

COAL CONTRACT INFORMATION - SPECIFICATION AND COSTS

Coal Contract Information - Specification and Costs (Page E-26)

General footnotes

Vendors C. Reiss and Midwest Energy provide transportation services only.

ELECTRIC DISTRIBUTION LINES

1. If a utility has available the number of poles, but not miles of pole line, it will be considered satisfactory to determine miles of pole line by multiplying number of poles by average length of span, indicating in a footnote the average span used.
2. Urban distribution lines and rural distribution lines are to be reported separately for Wisconsin and for outside the state.
3. Urban distribution lines are defined as lines inside corporate limits of incorporated places, lines in urban areas adjacent to such corporate limits, and lines in unincorporated communities with urban characteristics. All pole lines used for urban distribution, including joint distribution and transmission, other joint distribution lines, and joint use of foreign lines are to be reported.

Description (a)	Miles of: Pole Line (b)	U.G. Conduit (subway) (c)	Buried Cable (d)	
Lines in Wisconsin				
Urban distribution lines - primary voltage	2,187	45	698	**1**
Urban distribution lines - secondary voltage				**2**
Rural distribution lines - primary voltage	5,987	1	647	**3**
Rural distribution lines - secondary voltage				**4**
Total in Wisconsin	**8,174**	**46**	**1,345**	
Lines outside the state				
Urban distribution lines - primary voltage	95	1	5	**5**
Urban distribution lines - secondary voltage				**6**
Rural distribution lines - primary voltage	344		46	**7**
Rural distribution lines - secondary voltage				**8**
Total outside the state	**439**	**1**	**51**	
Total lines of utility	**8,613**	**47**	**1,396**	

ELECTRIC DISTRIBUTION METERS & LINE TRANSFORMERS

Watt-hour demand distribution meters should be included below but external demand meters should not be included.

Particulars (a)	Number of Watt-Hour Meters (b)	Line Transformers Number (c)	Line Transformers Total Cap. (kVA) (d)	
Number first of year	251,541	81,097	3,397	1
Acquired during year	35,188	1,083	81	2
Total	**286,729**	**82,180**	**3,478**	3
Retired during year	450	723	29	4
Sales, transfers or adjustments increase (decrease)				5
Number end of year	**286,279**	**81,457**	**3,449**	6
Number end of year accounted for as follows:				7
In customers' use	267,307	80,406	3,333	8
In utility's use	118			9
Inactive transformers on system				10
Locked meters on customers' premises	1,910			11
In stock	16,944	1,051	116	12
Total end of year	**286,279**	**81,457**	**3,449**	13

TRANSMISSION LINE STATISTICS

From (a)	To (b)	Operating Voltage (KV) (c)	Designed Voltage (KV) (d)	Type of Supporting Structure (e)	Length on Structure of Line Designated (f)	Length on Structures of Another Line (g)	Number of Circuits (h)	
ST CROIX RIVER	EAU CLAIRE	345.00	0.00	K-FRAME	61.06	0.00	1	1
		345.00	0.00		2.82	0.00	1	2
EAU CLAIRE	STEVENS POINT	345.00	0.00	K-FRAME	79.38	0.00	1	3
		345.00	0.00	TOWER	2.59	0.00	1	4
LA CROSSE	DPC TIE	161.00	0.00	H-FRAME	4.03	0.00	1	5
EAU CLAIRE	DPS TIE	161.00	0.00	H-FRAME	1.02	0.00	1	6
EAU CLAIRE	LA CROSSE	161.00	0.00	H-FRAME	80.28	0.00	1	7
TREMVAL	JACKSON COUNTY	161.00	0.00	H-FRAME	23.66	0.00	1	8
LA CROSSE	COULEE	161.00	0.00	H-FRAME	8.30	0.00	1	9
DPC	COULEE	161.00	0.00	H-FRAME	0.79	0.97	1	10
LA CROSSE	MONROE	161.00	0.00	H-FRAME	26.71	0.00	1	11
CRYSTAL CAVE	APPLE RIVER	161.00	0.00	1 POLE WD	38.97	1.04	1	12
EAU CLAIRE	ELK MOUND	161.00	0.00	H-FRAME	8.01	0.00	1	13
EAU CLAIRE	PRESTO	161.00	0.00	1 POLE WD	3.28	0.00	1	14
EAU CLAIRE	RED CEDAR	161.00	0.00	H-FRAME	23.23	0.00	1	15
HYDRO LANE	LINE 3213 TAP	161.00	0.00	1 POLE WD	10.16	0.00	1	16
RED CEDAR	CRYSTAL CAVE	161.00	0.00	1 POLE WD	28.80	0.00	2	17
STONE LAKE	MINONG	161.00	0.00	H-FRAME	20.38	0.00	1	18
STONE LAKE	GINGLES	161.00	0.00	1 POLE WD	63.31	0.00	1	19
								20
VARIOUS 115kv WOOD POLE		115.00	0.00	H-FRAME	383.54	11.92	1	21
VARIOUS 115kv TOWER		115.00	0.00	TOWER	52.97	0.00	1	22
VARIOUS 88kv WOOD POLE		88.00	0.00	H-FRAME	72.78	0.00	1	23
VARIOUS 69kv WOOD POLE		69.00	0.00	WOOD POLE	992.89	13.49	1	24
VARIOUS 69kv TOWER		69.00	0.00	TOWER	27.50	1.58	1	25
VARIOUS 34.5kv WOOD POLE		34.50	0.00	1 POLE WD	341.43	2.83	1	26
VARIOUS 23kv WOOD POLE		23.00	0.00	1 POLE WD	6.84	0.00	1	27
LA CROSSE	COULEE	69.00	0.00	UNDERGROUNE	0.34	0.00	1	28
EXPENSES APPLICABLE TO		0.00	0.00		0.00	0.00	0	29
ALL LINES		0.00	0.00		0.00	0.00	0	30
		0.00	0.00		0.00	0.00	0	31
				Total:	**2,365.07**	**31.83**	**28**	

TRANSMISSION LINE STATISTICS (cont.)

	Cost of Line			Expenses, Except Depreciation and Taxes				
Size of Conductor and Material (i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795AS	399,093	21,383,482	**21,782,575**				**0**	**1**
795AS	0	0	**0**				**0**	**2**
795AS	387,740	35,348,740	**35,736,480**				**0**	**3**
795AS	0	0	**0**				**0**	**4**
795AS	25,111	592,649	**617,760**				**0**	**5**
477AS	0	25,977	**25,977**				**0**	**6**
477AS	420,356	2,445,864	**2,866,220**				**0**	**7**
795AS	158,671	941,056	**1,099,727**				**0**	**8**
477AS	96,279	1,321,433	**1,417,712**				**0**	**9**
636AS	0	866,937	**866,937**				**0**	**10**
705AS	226,595	1,591,018	**1,817,613**				**0**	**11**
954AS	276,200	3,863,466	**4,139,666**				**0**	**12**
795AS	12,527	1,077,691	**1,090,218**				**0**	**13**
4/0 AS	44,366	149,301	**193,667**				**0**	**14**
	352,275	6,102,843	**6,455,118**				**0**	**15**
795AS	105,718	1,967,917	**2,073,635**				**0**	**16**
	35,141	481,372	**516,513**				**0**	**17**
636AS	30,345	0	**30,345**				**0**	**18**
795AS	519,901	19,936,952	**20,456,853**				**0**	**19**
			0				**0**	**20**
	2,479,280	41,671,662	**44,150,942**				**0**	**21**
	255,115	5,114,721	**5,369,836**				**0**	**22**
	135,680	3,063,396	**3,199,076**				**0**	**23**
	5,337,745	80,925,304	**86,263,049**				**0**	**24**
	99,449	1,760,494	**1,859,943**				**0**	**25**
	730,720	13,285,390	**14,016,110**				**0**	**26**
	7,931	519,203	**527,134**				**0**	**27**
	94,594	1,717,699	**1,812,293**				**0**	**28**
	0	0	**0**				**0**	**29**
	0	0	**0**	560,729	1,831,211	376,144	**2,768,084**	**30**
	0	0	**0**				**0**	**31**
	12,230,832	**246,154,567**	**258,385,399**	**560,729**	**1,831,211**	**376,144**	**2,768,084**	

TRANSMISSION LINES ADDED DURING YEAR

From (a)	To (b)	Line Length (Miles) (c)	Supporting Structure: Type (d)	Supporting Structure: Average Number per Mile (e)	Circuits per Structure: Present (f)	Circuits per Structure: Ultimate (g)	
NONE							1

TRANSMISSION LINES ADDED DURING YEAR (cont.)

Conductors			Voltage KV (Operating)	Line Cost					
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
			(k)						
								0	1

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Distribution					
Under 10 MVa Capacity					
Bloomer	Distribution	69.00	4.00	0.00	**1**
Cornell	Distribution	115.00	2.40	0.00	**2**
Cornell	Distribution	2.40	4.16	0.00	**3**
Hurley	Distribution	115.00	12.50	0.00	**4**
Menomonie	Distribution	69.00	4.16	0.00	**5**
Pokegama	Distribution	69.00	13.80	0.00	**6**
U.S. Rubber	Distribution	69.00	2.40	0.00	**7**
Viroqua	Distribution	69.00	4.16	0.00	**8**
88 additional substations under 10 MVA	Distribution				**9**
Total Distribution Substations Under 10 MVa Capacity		**Count: 9**			
10 MVa or Above Capacity					
Bayfield	Distribution	34.50	12.50	0.00	**10**
Arkansaw	Distribution	69.00	23.90	0.00	**11**
Bangor	Distribution	69.00	12.50	0.00	**12**
Blair	Distribution	69.00	12.50	0.00	**13**
Bloomer	Distribution	69.00	12.50	0.00	**14**
Cameron	Distribution	69.00	12.50	0.00	**15**
Camp McCoy	Distribution	69.00	7.20	0.00	**16**
Chippewa Falls	Distribution	69.00	12.50	0.00	**17**
Coulee Ave	Distribution	69.00	13.80	0.00	**18**
Coulee Ave	Distribution	161.00	69.00	13.80	**19**
Doughty Road	Distribution	69.00	23.90	0.00	**20**
Eagle Point	Distribution	115.00	23.90	0.00	**21**
Ellis	Distribution	69.00	12.50	0.00	**22**
Ellsworth Area	Distribution	69.00	12.50	0.00	**23**
Galesville	Distribution	69.00	12.50	0.00	**24**
Grassland	Distribution	69.00	12.50	0.00	**25**
Griffin Street	Distribution	69.00	12.50	0.00	**26**
Hallie	Distribution	69.00	12.50	0.00	**27**
Hay River	Distribution	69.00	23.90	0.00	**28**
Holmen Area	Distribution	69.00	13.80	0.00	**29**

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment			
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
0	0	1		0	0	1
8	1	0		0	0	2
6	1	1		0	0	3
7	1	0		0	0	4
6	1	0	Capacitor Bank	1	5	5
7	1	0		0	0	6
9	3	0		0	0	7
5	1	0	Capacitor Bank	1	5	8
361	128	8	Capacitor Bank	9	47	9
409	**137**	**10**		**11**	**57**	
14	1	0		0	0	10
11	1	0		0	0	11
11	1	0		0	0	12
11	1	0		0	0	13
11	1	0		0	0	14
11	1	0	Capacitor Bank	1	5	15
11	2	0		0	0	16
44	2	0		0	0	17
93	2	0		0	0	18
182	2	0	Capacitor Bank	1	5	19
14	1	0		0	0	20
47	1	0		0	0	21
56	2	0		0	0	22
11	1	0		0	0	23
11	1	0		0	0	24
14	1	0		0	0	25
11	1	0		0	0	26
56	2	0		0	0	27
11	1	0		0	0	28
25	2	0	Capacitor Bank	1	5	29

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Distribution					
10 MVa or Above Capacity					
Hurley	Distribution	115.00	13.80	0.00	**30**
Jeffers Road	Distribution	161.00	23.90	0.00	**31**
Lake Camelia	Distribution	69.00	23.00	0.00	**32**
London	Distribution	69.00	12.50	0.00	**33**
Loyal	Distribution	69.00	12.50	0.00	**34**
Madison Street	Distribution	69.00	12.50	0.00	**35**
Mayfair	Distribution	161.00	13.80	0.00	**36**
Menomonie	Distribution	69.00	12.50	0.00	**37**
Naples	Distribution	69.00	12.50	0.00	**38**
Neillsville	Distribution	69.00	12.50	0.00	**39**
New Richmond	Distribution	69.00	23.90	0.00	**40**
North Fork	Distribution	34.50	12.50	0.00	**41**
Onalaska	Distribution	69.00	13.80	0.00	**42**
Osceola	Distribution	69.00	12.50	0.00	**43**
Otter Creek	Distribution	69.00	12.50	0.00	**44**
Phillips	Distribution	115.00	12.50	0.00	**45**
Prescott	Distribution	69.00	12.50	0.00	**46**
Rice Lake	Distribution	69.00	12.50	0.00	**47**
Rush River	Distribution	69.00	23.00	0.00	**48**
Rusk	Distribution	69.00	12.50	0.00	**49**
Second Street	Distribution	34.50	13.80	0.00	**50**
Sheldon Pump	Distribution	115.00	4.16	0.00	**51**
Sparta	Distribution	69.00	12.50	0.00	**52**
Spencer	Distribution	69.00	12.50	0.00	**53**
Stanley Area	Distribution	69.00	23.90	0.00	**54**
Strum	Distribution	69.00	12.50	0.00	**55**
Sumner	Distribution	69.00	23.90	0.00	**56**
Swift Creek	Distribution	69.00	13.80	0.00	**57**
Truax	Distribution	69.00	12.50	0.00	**58**
Turtle Lake	Distribution	69.00	12.50	0.00	**59**
U. S. Rubber	Distribution	69.00	4.16	0.00	**60**

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment			
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
37	1	0		0	0	30
94	2	0		0	0	31
14	1	0		0	0	32
56	2	0		0	0	33
11	1	0		0	0	34
28	1	0		0	0	35
93	2	0		0	0	36
56	2	0		0	0	37
11	1	0		0	0	38
25	2	0	Capacitor Bank	1	5	39
14	1	0	Capacitor Bank	2	16	40
21	2	0		0	0	41
14	1	0	Capacitor Bank	1	5	42
25	2	0	Capacitor Bank	2	17	43
56	2	0		0	0	44
25	2	0		0	0	45
11	1	0	Capacitor Bank	1	5	46
56	2	0	Capacitor Bank	1	5	47
30	2	0		0	0	48
11	1	0		0	0	49
14	1	0		0	0	50
14	1	0		0	0	51
56	2	0		0	0	52
25	2	0	Capacitor Bank	1	5	53
42	2	0		0	0	54
11	1	0	Capacitor Bank	1	5	55
14	1	0		0	0	56
56	2	0	Capacitor Bank	1	5	57
56	2	0		0	0	58
11	1	0		0	0	59
11	4	0		0	0	60

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Distribution					
10 MVa or Above Capacity					
Viroqua	Distribution	69.00	13.80	0.00	61
Waumandee	Distribution	69.00	23.90	0.00	62
West Salem	Distribution	69.00	23.90	0.00	63
Willow River	Distribution	115.00	23.00	0.00	64
Woodmour	Distribution	69.00	23.00	0.00	65
Total Distribution Substations 10 MVa or Above Capacity		**Count: 56**			
Total Distribution Substations		**Count: 65**			
Substation Type: Transmission					
Under 10 MVa Capacity					
Cedar Falls	Transmission	69.00	2.40	0.00	66
Jim Falls	Transmission	12.50	7.20	0.00	67
Ironwood (MI)	Transmission	34.50	4.16	0.00	68
14 additional substations under 10 MVA	Transmission				69
Total Transmission Substations Under 10 MVa Capacity		**Count: 4**			
10 MVa or Above Capacity					
Bay Front	Transmission	88.00	34.50	0.00	70
Bay Front	Transmission	88.00	13.80	0.00	71
Bay Front	Transmission	34.50	13.80	0.00	72
Bay Front	Transmission	88.00	13.80	0.00	73
Bay Front	Transmission	88.00	69.00	0.00	74
Bay Front	Transmission	115.00	88.00	0.00	75
Big Falls	Transmission	69.00	2.40	0.00	76
Cedar Falls	Transmission	69.00	23.90	0.00	77
Chippewa Falls	Transmission	69.00	4.00	0.00	78
Cornell Hydro	Transmission	115.00	7.20	0.00	79
Crystal Cave	Transmission	161.00	115.00	13.80	80
Eau Claire	Transmission	161.00	69.00	13.80	81
Eau Claire	Transmission	345.00	161.00	13.80	82
Eau Claire Dells	Transmission	69.00	2.40	0.00	83
Farmers Inn	Transmission	69.00	12.50	0.00	84

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment			
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
13	1	0		0	0	61
11	1	0		0	0	62
56	2	0	Capacitor Bank	1	5	63
140	2	0		0	0	64
11	1	0	Capacitor Bank	1	5	65
1884	**84**	**0**		**16**	**93**	
2293	**221**	**10**		**27**	**150**	
7	1	0		0	0	66
1	3	0		0	0	67
6	4	1		0	0	68
55	21	3	Capacitor Bank	4	33	69
69	**29**	**4**		**4**	**33**	
20	1	0		0	0	70
27	6	1		0	0	71
13	2	0	Capacitor Bank	2	12	72
52	2	0		0	0	73
20	1	0		0	0	74
50	1	0	Capacitor Bank	1	11	75
10	2	1		0	0	76
11	1	0		0	0	77
46	2	0		0	0	78
40	1	0		0	0	79
187	1	0	Capacitor Bank	2	80	80
224	2	0	Capacitor Bank	4	356	81
600	2	0		0	0	82
12	3	0		0	0	83
14	1	0	Capacitor Bank	1	5	84

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Transmission					
10 MVa or Above Capacity					
Farmers Inn	Transmission	161.00	69.00	0.00	**85**
Flambeau	Transmission	34.50	13.80	0.00	**86**
French Island	Transmission	69.00	13.80	0.00	**87**
Gingles	Transmission	161.00	115.00	0.00	**88**
Gingles	Transmission	115.00	69.00	0.00	**89**
Gingles	Transmission	115.00	34.50	0.00	**90**
Holcombe	Transmission	115.00	7.20	0.00	**91**
Hydro Lane	Transmission	161.00	115.00	0.00	**92**
Hydro Lane	Transmission	115.00	69.00	0.00	**93**
Hydro Lane	Transmission	115.00	23.90	0.00	**94**
Hydro Lane	Transmission	115.00	12.50	0.00	**95**
Jackson County	Transmission	161.00	69.00	13.50	**96**
Jim Falls	Transmission	115.00	69.00	0.00	**97**
Jim Falls	Transmission	115.00	7.20	0.00	**98**
Jim Falls	Transmission	69.00	12.50	0.00	**99**
La Crosse	Transmission	161.00	69.00	13.80	**100**
La Crosse	Transmission	69.00	13.80	0.00	**101**
Marshland	Transmission	161.00	69.00	13.80	**102**
Monroe County	Transmission	161.00	69.00	0.00	**103**
Osprey	Transmission	69.00	23.90	0.00	**104**
Osprey	Transmission	115.00	69.00	0.00	**105**
Park Falls 115KV	Transmission	115.00	34.50	0.00	**106**
Pine Lake	Transmission	115.00	69.00	0.00	**107**
Pine Lake	Transmission	161.00	115.00	0.00	**108**
Prentice	Transmission	115.00	69.00	0.00	**109**
Prentice	Transmission	115.00	12.50	0.00	**110**
Red Cedar	Transmission	161.00	69.00	0.00	**111**
Red Cedar	Transmission	69.00	12.50	0.00	**112**
River Falls	Transmission	115.00	69.00	0.00	**113**
St. Croix Falls	Transmission	69.00	12.50	0.00	**114**
St. Croix Falls	Transmission	12.50	2.40	0.00	**115**

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
50	1	0		0	0	**85**
20	1	0		0	0	**86**
221	3	0	Capacitor Bank	1	5	**87**
187	1	0		0	0	**88**
42	1	0		0	0	**89**
94	2	0	Capacitor Bank	2	12	**90**
38	3	0		0	0	**91**
187	1	0		0	0	**92**
42	1	0		0	0	**93**
47	1	0		0	0	**94**
28	1	0		0	0	**95**
46	1	0		0	0	**96**
112	1	0		0	0	**97**
67	2	0		0	0	**98**
11	1	0		0	0	**99**
140	2	0		0	0	**100**
93	2	0	Capacitor Bank	1	5	**101**
224	2	0		0	0	**102**
70	1	0	Capacitor Bank	1	14	**103**
11	1	0		0	0	**104**
47	1	0		0	0	**105**
56	2	0	Capacitor Bank	1	6	**106**
224	2	0		0	0	**107**
112	1	1		0	0	**108**
50	1	0		0	0	**109**
11	1	0	Capacitor Bank	1	13	**110**
70	1	0		0	0	**111**
56	2	0		0	0	**112**
70	1	0	Capacitor Bank	1	5	**113**
28	1	0		0	0	**114**
29	5	1		0	0	**115**

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution.

Name and Location of Substation (a)	Character of Substation (b)	Voltage (in MVa) Primary (c)	Secondary (d)	Tertiary (e)	
Substation Type: Transmission					
10 MVa or Above Capacity					
Seven Mile	Transmission	161.00	69.00	13.80	**116**
Stone Lake	Transmission	161.00	69.00	0.00	**117**
T-Corners	Transmission	115.00	69.00	13.80	**118**
T-Corners	Transmission	69.00	23.90	0.00	**119**
Trails End	Transmission	69.00	23.90	0.00	**120**
Tremval	Transmission	161.00	69.00	13.80	**121**
Wheaton	Transmission	69.00	13.20	0.00	**122**
Wheaton	Transmission	161.00	13.80	0.00	**123**
Whitetail	Transmission	69.00	34.50	7.20	**124**
Whitetail	Transmission	69.00	13.80	0.00	**125**
Wissota	Transmission	69.00	13.80	0.00	**126**
Ironwood (MI)	Transmission	115.00	34.50	0.00	**127**
Ironwood (MI)	Transmission	88.00	34.50	0.00	**128**
Stone Lake	Transmission	345.00	161.00	13.80	**129**
Total Transmission Substations 10 MVa or Above Capacity		**Count: 60**			
Total Transmission Substations		**Count: 64**			

SUBSTATIONS (cont.)

5. Show in columns (i), (j) and (k) special equipment leased from othersjointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (in Service) (in MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment			
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVa) (k)	
112	1	0		0	0	**116**
70	1	0	Capacitor Bank	3	47	**117**
182	2	0	Capacitor Bank	5	140	**118**
56	2	0	Capacitor Bank	1	5	**119**
11	1	0		0	0	**120**
70	1	1		0	0	**121**
0	0	1		0	0	**122**
435	3	0		0	0	**123**
20	1	1	Capacitor Bank	1	5	**124**
11	1	0		0	0	**125**
50	6	1		0	0	**126**
100	2	0	Capacitor Bank	1	11	**127**
25	1	0		0	0	**128**
336	1	0		0	0	**129**
5287	**98**	**8**		**29**	**732**	
5356	**127**	**12**		**33**	**765**	

TRANSMISSION OF ELECTRICITY FOR OTHERS

1. Report all transmision of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the year.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column(a) the company or public authority that paid for the transmission service. Report in column(b) the company or public authority that the energy was received from and in column(c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractural terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See FERC General Instruction for definition of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number. Use footnotes to list additional FERC Rate Schedules or contract designations under which service, as identified in column (d), is provided.

Payment By (Company of Public Authority) (a)	Energy Received From (Company of Public Authority) (b)	Energy Delivered To (Company of Public Authority) (c)	Statistical Classification (d)	FERC Rate Schedule of Tariff Number (e)	
NONE					1

TRANSMISSION OF ELECTRICITY FOR OTHERS (cont.)

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation of the substation, or other apropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (li) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes on the Electric Energy Account schedule, lines 12 and 13, respectively.
11. Footnote entries and provide explanations following all required data.

Point of Receipt/ Point of Delivery (Substation or Other Designation (f), (g)	Billing Demand (MW) (h)	Transfer of Energy		Revenue from Transmission of Electricity for Others				
		MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (k)	Energy Charges (l)	Other Charges (m)	Total Revenues (n)	
							0	1

TRANSMISSION OF ELECTRICITY BY OTHERS

1. Report all transmision of electricity, i.e., wheeling, provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the year.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use footnotes as necessary to report all companies or public authorities that provided transmission service for the year.
3. In column (a) enter a Statistical Classification code based on the original contractural terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Point to Point Transmission Reservation, NF - non-firm transmission service, and OS - Other Transmission Service. See FERC General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. In column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Footnote entries and provide explanations following all required data.

Name of Company or Public Authority (Footnote Affiliation) (a)	Statistical Classification (b)	Transfer of Energy: Megawatt-Hours Received (c)	Transfer of Energy: Megawatt-Hours Delivered (d)	Expenses for Transmission of Electricity by Others: Demand Charges (e)	Energy Charges (f)	Other Charges (g)	Total Cost of Transmission (h)	
NONE								1
	Total:	0	0	0	0	0	0	

POWER COST ADJUSTMENT CLAUSE

Report below the revenue derived from the power cost adjustment clause for the year for each rate schedule that is reported on page E-8. Do not combine any of the rate schedules.

Rate Schedules (a)	PCAC Revenues (Wisconsin only) (b)	
Account 440		
Rg-1 Residential		1
Rg-2 Residential Time of Day		2
RG-3 Residential Managed Service		3
Fg-1 Farm		4
Cg-6 Optional Off Peak		5
S-1 Automatic Protective		6
Total Account 440:	0	
Account 441		
NONE		7
Total Account 441:	0	
Account 442		
Cg-1 Sm General TOD		8
Cg-2 Sm General		9
Cg-5 General		10
Cg-6 Opt Off Peak		11
Cp-2 Peak Controlled General		12
Cg-9 Lg General TOD		13
Cp-1 Peak Controlled TOD		14
S-1 Automatic Protective		15
Rtp-1 Bundled Requirements		16
Total Account 442:	0	
Account 444		
Ms-2 Co. Owned Street Lighting		17
Ms-3 Co. Owned Street Lighting		18
Ms-4 Cust. Owned Street Lighting		19
Ms-6 UG Area Lighting		20
Ms-7 Metered Street Lighting		21
Total Account 444:	0	
Account 445		
Mp-1 Muni. Water Pumping		22
Total Account 445:	0	
Total:	0	

POWER COST ADJUSTMENT CLAUSE

Power Cost Adjustment Clause (Page E-38)

General footnotes

Northern States Power Company - Wisconsin had no Power Cost Adjustment Clause revenue in 2009.

POWER COST ADJUSTMENT CLAUSE FACTOR

1. Report below in col. (b) the monthly PCAC Factors actually applied in determining monthly revenues for the year.
2. The monthly PCAC Factor may be stated as dollars per Kwh according to your power cost adjustment clause.

Month (a)	Adjustment Factor (Wisconsin only) (b)	
January		1
February		2
March		3
April		4
May		5
June		6
July		7
August		8
September		9
October		10
November		11
December		12

POWER COST ADJUSTMENT CLAUSE FACTOR

Power Cost Adjustment Clause Factor (Page E-39)

General footnotes

Northern States Power Company - Wisconsin had no Power Cost Adjustment Clause factors in place during 2009.

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Ashland County	
Cities	
ASHLAND	4,487
MELLEN	497
Total Cities:	**4,984**
Villages	
BUTTERNUT	279
Total Villages:	**279**
Towns	
AGENDA	94
ASHLAND	118
CHIPPEWA	146
GINGLES	302
GORDON	22
JACOBS	382
LA POINTE	887
MARENGO	88
MORSE	84
PEEKSVILLE	19
SANBORN	171
SHANAGOLDEN	
WHITE RIVER	224
Total Towns:	**2,537**
Total Ashland County:	**7,800**
Barron County	
Cities	
BARRON	17
CHETEK	1,310
RICE LAKE	18
Total Cities:	**1,345**
Villages	
ALMENA	399
CAMERON	910
DALLAS	204
HAUGEN	184
NEW AUBURN	6
PRAIRIE FARM	247
TURTLE LAKE	580
Total Villages:	**2,530**
Towns	
ALMENA	290
ARLAND	140
BARRON	73
BEAR LAKE	28

Barron County Towns	Customers End of Year (b)
CEDAR LAKE	1,161
CHETEK	357
CLINTON	228
CRYSTAL LAKE	93
CUMBERLAND	42
DALLAS	147
DOVRE	74
DOYLE	225
LAKELAND	75
MAPLE GROVE	181
MAPLE PLAIN	42
OAK GROVE	246
PRAIRIE FARM	194
PRAIRIE LAKE	92
RICE LAKE	591
SIOUX CREEK	85
STANFOLD	52
STANLEY	273
SUMNER	52
TURTLE LAKE	147
VANCE CREEK	134
Total Towns:	**5,022**
Total Barron County:	**8,897**
Bayfield County	
Cities	
BAYFIELD	769
WASHBURN	1,189
Total Cities:	**1,958**
Villages	
MASON	58
Total Villages:	**58**
Towns	
BARKSDALE	245
BAYFIELD	546
BAYVIEW	168
BELL	152
CABLE	569
CLOVER	142
DRUMMOND	265
EILEEN	124
GRAND VIEW	110
IRON RIVER	2
KELLY	106
KEYSTONE	11

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Bayfield County	
Towns	
LINCOLN	90
MASON	46
NAMEKAGON	244
ORIENTA	46
OULU	92
PORT WING	309
RUSSELL	472
TRIPP	16
WASHBURN	60
Total Towns:	**3,815**
Total Bayfield County:	**5,831**
Buffalo County	
Cities	
ALMA	554
BUFFALO CITY	55
FOUNTAIN CITY	547
MONDOVI	1,501
Total Cities:	**2,657**
Villages	
COCHRANE	306
NELSON	240
Total Villages:	**546**
Towns	
ALMA	6
BELVIDERE	57
BUFFALO	227
CANTON	50
GLENCOE	4
LINCOLN	48
MAXVILLE	
MONDOVI	4
MONTANA	16
NAPLES	106
NELSON	5
WAUMANDEE	196
Total Towns:	**719**
Total Buffalo County:	**3,922**
Chippewa County	
Cities	
BLOOMER	7
CHIPPEWA FALLS	7,173
CORNELL	2

Chippewa County Cities	Customers End of Year (b)
EAU CLAIRE	666
STANLEY	1,175
Total Cities:	**9,023**
Villages	
BOYD	324
CADOTT	3
LAKE HALLIE	870
NEW AUBURN	244
Total Villages:	**1,441**
Towns	
ANSON	908
AUBURN	103
BLOOMER	75
COOKS VALLEY	158
DELMAR	134
EAGLE POINT	922
EDSON	170
GOETZ	5
HALLIE	1,763
HOWARD	44
LAFAYETTE	2,782
RUBY	19
SIGEL	100
TILDEN	593
WHEATON	270
WOODMOHR	119
Total Towns:	**8,165**
Total Chippewa County:	**18,629**
Clark County	
Cities	
ABBOTSFORD	865
COLBY	567
GREENWOOD	630
LOYAL	723
NEILLSVILLE	1,476
OWEN	585
THORP	955
Total Cities:	**5,801**
Villages	
CURTISS	115
DORCHESTER	478
GRANTON	241
UNITY	93

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Clark County	
Villages	
WITHEE	298
Total Villages:	**1,225**
Towns	
BEAVER	23
COLBY	121
EATON	151
FOSTER	17
FREMONT	216
GRANT	161
GREEN GROVE	26
HIXON	59
HOARD	53
LONGWOOD	31
LOYAL	149
LYNN	79
MAYVILLE	95
MENTOR	158
PINE VALLEY	194
RESEBURG	67
SHERMAN	80
THORP	76
UNITY	218
WARNER	10
WESTON	155
WITHEE	219
WORDEN	33
YORK	147
Total Towns:	**2,538**
Total Clark County:	**9,564**
Crawford County	
Villages	
DE SOTO	61
Total Villages:	**61**
Towns	
FREEMAN	11
Total Towns:	**11**
Total Crawford County:	**72**
Dunn County	
Cities	
MENOMONIE	6,952
Total Cities:	**6,952**
Dunn County	
Villages	
BOYCEVILLE	557
COLFAX	632
DOWNING	106
ELK MOUND	398
KNAPP	264
RIDGELAND	209
WHEELER	189
Total Villages:	**2,355**
Towns	
COLFAX	32
DUNN	183
EAU GALLE	241
ELK MOUND	89
HAY RIVER	3
LUCAS	66
MENOMONIE	823
NEW HAVEN	13
OTTER CREEK	1
RED CEDAR	562
SAND CREEK	170
SHERIDAN	46
SHERMAN	86
SPRING BROOK	293
SPRINGBROOK	
STANTON	64
TAINTER	412
TIFFANY	97
WESTON	73
WILSON	62
Total Towns:	**3,316**
Total Dunn County:	**12,623**
Eau Claire County	
Cities	
ALTOONA	2,398
AUGUSTA	809
EAU CLAIRE	30,286
Total Cities:	**33,493**
Villages	
FAIRCHILD	295
FALL CREEK	661
Total Villages:	**956**
Towns	
BRIDGE CREEK	63

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Eau Claire County	
Towns	
BRUNSWICK	122
CLEAR CREEK	70
DRAMMEN	5
FAIRCHILD	72
LINCOLN	73
OTTER CREEK	77
SEYMOUR	380
UNION	989
WASHINGTON	1,619
Total Towns:	**3,470**
Total Eau Claire County:	**37,919**
Iron County	
Cities	
HURLEY	1,189
MONTREAL	538
Total Cities:	**1,727**
Towns	
ANDERSON	47
CAREY	88
GURNEY	59
KIMBALL	293
KNIGHT	144
MERCER	1,886
OMA	150
PENCE	122
SAXON	168
SHERMAN	26
Total Towns:	**2,983**
Total Iron County:	**4,710**
Jackson County	
Villages	
ALMA CENTER	275
HIXTON	273
MELROSE	299
TAYLOR	266
Total Villages:	**1,113**
Towns	
ADAMS	95
ALMA	110
CLEVELAND	24
CURRAN	32
GARDEN VALLEY	81

Jackson County Towns	Customers End of Year (b)
HIXTON	84
MELROSE	80
NORTH BEND	111
NORTHFIELD	110
SPRINGFIELD	98
Total Towns:	**825**
Total Jackson County:	**1,938**
La Crosse County	
Cities	
LA CROSSE	25,690
ONALASKA	6,390
Total Cities:	**32,080**
Villages	
HOLMEN	2,766
ROCKLAND	269
WEST SALEM	2,279
Total Villages:	**5,314**
Towns	
BANGOR	80
BARRE	552
BURNS	172
CAMPBELL	2,173
FARMINGTON	465
GREENFIELD	454
HAMILTON	1,029
HOLLAND	83
MEDARY	572
ONALASKA	617
SHELBY	1,419
WASHINGTON	52
Total Towns:	**7,668**
Total La Crosse County:	**45,062**
Lincoln County	
Towns	
SOMO	50
Total Towns:	**50**
Total Lincoln County:	**50**
Marathon County	
Cities	
ABBOTSFORD	328
COLBY	290
Total Cities:	**618**

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Marathon County	
Villages	
ATHENS	604
SPENCER	978
UNITY	137
Total Villages:	**1,719**
Towns	
BERN	29
BRIGHTON	29
FRANKFORT	242
HALSEY	40
HOLTON	13
HULL	188
JOHNSON	404
RIETBROCK	82
SPENCER	41
WIEN	127
Total Towns:	**1,195**
Total Marathon County:	**3,532**
Marquette County	
Towns	
BUFFALO	
Total Towns:	**0**
Total Marquette County:	**0**
Monroe County	
Cities	
SPARTA	4,677
Total Cities:	**4,677**
Villages	
CASHTON	15
MELVINA	56
NORWALK	292
Total Villages:	**363**
Towns	
ANGELO	364
GREENFIELD	2
JEFFERSON	129
LA FAYETTE	165
LEON	157
LITTLE FALLS	492
NEW LYME	65
PORTLAND	78
RIDGEVILLE	40
SHELDON	6

Monroe County	Customers End of Year (b)
Towns	
SPARTA	1,285
WELLS	49
Total Towns:	**2,832**
Total Monroe County:	**7,872**
Oneida County	
Towns	
LYNNE	63
Total Towns:	**63**
Total Oneida County:	**63**
Pepin County	
Cities	
DURAND	206
Total Cities:	**206**
Villages	
PEPIN	599
STOCKHOLM	122
Total Villages:	**721**
Towns	
DURAND	1,010
LIMA	116
PEPIN	334
STOCKHOLM	30
WATERVILLE	372
WAUBEEK	111
Total Towns:	**1,973**
Total Pepin County:	**2,900**
Pierce County	
Cities	
PRESCOTT	2,041
Total Cities:	**2,041**
Villages	
BAY CITY	292
ELLSWORTH	1,362
ELMWOOD	459
MAIDEN ROCK	120
PLUM CITY	318
SPRING VALLEY	549
Total Villages:	**3,100**
Towns	
CLIFTON	343
EL PASO	8
ELLSWORTH	54
GILMAN	153

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Pierce County	
Towns	
HARTLAND	34
ISABELLE	128
MAIDEN ROCK	51
OAK GROVE	63
RIVER FALLS	25
ROCK ELM	214
SALEM	29
SPRING LAKE	186
TRENTON	505
TRIMBELLE	16
UNION	205
Total Towns:	**2,014**
Total Pierce County:	**7,155**
Polk County	
Cities	
AMERY	1,636
SAINT CROIX FALLS	1,204
Total Cities:	**2,840**
Villages	
CLAYTON	276
CLEAR LAKE	597
DRESSER	452
LUCK	633
OSCEOLA	1,312
TURTLE LAKE	48
Total Villages:	**3,318**
Towns	
ALDEN	398
APPLE RIVER	42
BEAVER	32
BLACK BROOK	186
BONE LAKE	155
CLAYTON	458
CLEAR LAKE	355
FARMINGTON	251
GARFIELD	348
JOHNSTOWN	4
LINCOLN	682
LUCK	207
MCKINLEY	117
OSCEOLA	621

Location (a)	Customers End of Year (b)
Polk County	
Towns	
SAINT CROIX FALLS	91
Total Towns:	**3,947**
Total Polk County:	**10,105**
Price County	
Cities	
PARK FALLS	1,607
PHILLIPS	1,129
Total Cities:	**2,736**
Villages	
CATAWBA	96
KENNAN	103
PRENTICE	410
Total Villages:	**609**
Towns	
CATAWBA	3
EISENSTEIN	128
ELK	361
EMERY	32
FIFIELD	200
FLAMBEAU	66
GEORGETOWN	78
HACKETT	9
HARMONY	78
HILL	2
KENNAN	22
KNOX	149
LAKE	573
OGEMA	171
PRENTICE	133
WORCESTER	326
Total Towns:	**2,331**
Total Price County:	**5,676**
Rusk County	
Cities	
LADYSMITH	2,009
Total Cities:	**2,009**
Villages	
BRUCE	505
CONRATH	57
GLEN FLORA	80
HAWKINS	228
INGRAM	62

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Rusk County	
Villages	
SHELDON	186
TONY	87
WEYERHAEUSER	187
Total Villages:	**1,392**
Towns	
ATLANTA	133
BIG BEND	38
BIG FALLS	28
DEWEY	240
FLAMBEAU	305
GRANT	417
GROW	142
HAWKINS	8
LAWRENCE	13
MARSHALL	139
RICHLAND	10
STRICKLAND	14
STUBBS	361
THORNAPPLE	92
TRUE	95
WILSON	3
Total Towns:	**2,038**
Total Rusk County:	**5,439**
Saint Croix County	
Cities	
GLENWOOD CITY	649
HUDSON	6,591
NEW RICHMOND	111
Total Cities:	**7,351**
Villages	
BALDWIN	1,678
DEER PARK	160
HAMMOND	718
NORTH HUDSON	1,562
ROBERTS	791
SOMERSET	1,166
STAR PRAIRIE	303
WILSON	88
WOODVILLE	651
Total Villages:	**7,117**
Towns	
BALDWIN	314
CADY	114

Saint Croix County Towns	Customers End of Year (b)
CYLON	77
EAU GALLE	81
EMERALD	100
FOREST	158
GLENWOOD	160
HAMMOND	617
HUDSON	1,978
KINNICKINNIC	178
PLEASANT VALLEY	12
RICHMOND	237
RUSH RIVER	76
SAINT JOSEPH	635
SOMERSET	537
SPRINGFIELD	204
STANTON	171
STAR PRAIRIE	1,410
TROY	434
WARREN	189
Total Towns:	**7,682**
Total Saint Croix County:	**22,150**
Sawyer County	
Cities	
HAYWARD	1,769
Total Cities:	**1,769**
Towns	
BASS LAKE	1,347
COUDERAY	78
EDGEWATER	87
HAYWARD	1,369
LENROOT	1,126
ROUND LAKE	50
SAND LAKE	1,342
SPIDER LAKE	3
Total Towns:	**5,402**
Total Sawyer County:	**7,171**
Taylor County	
Cities	
MEDFORD	2
Total Cities:	**2**
Villages	
GILMAN	264
LUBLIN	104
RIB LAKE	504

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Taylor County	
Villages	
STETSONVILLE	283
Total Villages:	**1,155**
Towns	
CHELSEA	78
FORD	29
GREENWOOD	44
LITTLE BLACK	133
RIB LAKE	122
ROOSEVELT	101
TAFT	62
WESTBORO	261
Total Towns:	**830**
Total Taylor County:	**1,987**
Trempealeau County	
Cities	
BLAIR	722
GALESVILLE	844
INDEPENDENCE	802
OSSEO	954
WHITEHALL	3
Total Cities:	**3,325**
Villages	
ELEVA	372
ETTRICK	277
PIGEON FALLS	226
STRUM	496
TREMPEALEAU	2
Total Villages:	**1,373**
Towns	
ALBION	161
BURNSIDE	37
CALEDONIA	21
DODGE	178
ETTRICK	49
GALE	216
HALE	6
LINCOLN	177
PIGEON	156
PRESTON	109
SUMNER	22
TREMPEALEAU	175

Location (a)	Customers End of Year (b)
Trempealeau County	
Towns	
UNITY	37
Total Towns:	**1,344**
Total Trempealeau County:	**6,042**
Vernon County	
Cities	
VIROQUA	2,284
Total Cities:	**2,284**
Villages	
CHASEBURG	164
COON VALLEY	432
DE SOTO	184
GENOA	153
STODDARD	443
Total Villages:	**1,376**
Towns	
BERGEN	274
CHRISTIANA	59
COON	322
GENOA	60
HAMBURG	156
HARMONY	111
JEFFERSON	148
STERLING	4
VIROQUA	295
WHEATLAND	12
Total Towns:	**1,441**
Total Vernon County:	**5,101**
Vilas County	
Towns	
BOULDER JUNCTION	182
MANITOWISH WATERS	1,497
PRESQUE ISLE	1,231
WINCHESTER	629
Total Towns:	**3,539**
Total Vilas County:	**3,539**
Washburn County	
Cities	
SHELL LAKE	954
Total Cities:	**954**

ELECTRIC CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Washburn County	
Villages	
BIRCHWOOD	384
Total Villages:	**384**
Towns	
BARRONETT	17
BASHAW	47
BEAVER BROOK	77
BIRCHWOOD	388
LONG LAKE	264
SARONA	53
SPRINGBROOK	158
STINNETT	13
STONE LAKE	182
TREGO	217
Total Towns:	**1,416**
Total Washburn County:	**2,754**
Total Company:	**248,503**

GAS OPERATING REVENUES & EXPENSES

Particulars (a)	This Year (b)	Last Year (c)	
Operating Revenues			
Sales of Gas			
Sales of Gas (480-484)	129,633,684	179,983,967	1
Total Sales of Gas	**129,633,684**	**179,983,967**	
Other Operating Revenues			
Forfeited Discounts (487)	318,882	383,301	2
Miscellaneous Service Revenues (488)	196,050	261,747	3
Transportation (489)	1,474,304	1,474,687	4
Rent from Property (493)	0	0	5
Other Gas Revenues (495)	855,914	(1,104,960)	6
Penalty Revenue (497)	0	0	7
Utility Revenue Incentive (PBR) (498)	0	0	8
Total Other Operating Revenues	**2,845,150**	**1,014,775**	
Total Operating Revenues	**132,478,834**	**180,998,742**	
Production Expenses			
Manufactured Gas Production Expenses (700-742)	1,108,967	1,089,619	9
Natural Gas Production Expenses (750-792)	0	0	10
Purchased Gas Expenses (804-813)	91,606,330	138,627,032	11
Total Production Expenses	**92,715,297**	**139,716,651**	
Operation and Maintenance Expenses			
Storage Expenses (840-848.3)	336,375	350,550	12
Transmission Expenses (850-867)	0	0	13
Distribution Expenses (870-894)	6,933,404	6,491,326	14
Customer Accounts Expenses (901-905)	3,970,730	4,075,260	15
Customer Service Expenses (907-910)	3,486,517	3,302,256	16
Sales Promotion Expenses (911-916)	75,542	102,609	17
Administrative and General Expenses (920-935)	4,990,841	4,002,645	18
Total Operation and Maintenance Expenses	**19,793,409**	**18,324,646**	
Other Operating Expenses			
Depreciation Expense (403)	7,416,795	6,826,176	19
Amortization Limited-Term Utility Investment (404)	396,867	459,267	20
Amortization of Other Utility Plant (405)	55,220	57,224	21
Amortization of Utility Plant Acquisition Adjustment (406)	0	0	22
Amortization of Property Losses (407.1)	0	0	23
Amortization of Conversion Expenses (407.2)	0	0	24
Regulatory Debits (407.3)	0	0	25
(Less) Regulatory Credits (407.4)	0	0	26
Taxes Other Than Income Taxes (408.1)	2,445,084	2,056,690	27
Income Taxes (409.1)	(750,305)	2,387,754	28
Provision for Deferred Income Taxes (410.1, 411.1)	3,826,838	2,051,702	29
Accretion Expense FERC (411.10)	0	0	30

GAS OPERATING REVENUES & EXPENSES

Particulars (a)	This Year (b)	Last Year (c)	
Other Operating Expenses			
Investment Tax Credit Adjustment (411.4)	(26,835)	(27,130)	**31**
Total Other Operating Expenses	**13,363,664**	**13,811,683**	
Total Operating Expenses	**125,872,370**	**171,852,980**	
NET OPERATING INCOME	**6,606,464**	**9,145,762**	

GAS EXPENSES

Report all amounts on the basis and in conformity with the uniform system of accounts and accounting directives prescribed by this commission. Allocate "Total Operations" amounts jurisdictionally between Wisconsin (PSCW) jurisdiction and all other jurisdiction.

Particulars (a)	Wisconsin Jurisdictional Operations Labor (b)	Wisconsin Jurisdictional Operations Other (c)	Other Jurisdictional Operations Labor (d)	Other Jurisdictional Operations Other (e)	Total Operations (f)	
Production Expenses						
Manufactured Gas Production Expenses (700-742)	18,213	1,089,552	1,202		**1,108,967**	1
Natural Gas Production Expenses (750-792)					**0**	2
Purchased Gas Expenses (804-813)	174,839	84,854,216	8,943	6,568,332	**91,606,330**	3
Total Production Expenses	**193,052**	**85,943,768**	**10,145**	**6,568,332**	**92,715,297**	
Operation and Maintenance Expenses						
Storage Expenses (840-848.3)	136,386	179,100	9,030	11,859	**336,375**	4
Transmission Expenses (850-867)					**0**	5
Distribution Expenses (870-894)	4,316,266	2,293,724	203,985	119,429	**6,933,404**	6
Customer Accounts Expenses (901-905)	1,263,915	2,492,254	67,702	146,859	**3,970,730**	7
Customer Service Expenses (907-910)	348,681	3,100,942	18,666	18,228	**3,486,517**	8
Sales Promotion Expenses (911-916)	38,393	33,311	2,055	1,783	**75,542**	9
Administrative and General Expenses (920-935)	3,042,148	1,711,961	150,540	86,192	**4,990,841**	10
Total Operation and Maintenance Expenses	**9,145,789**	**9,811,292**	**451,978**	**384,350**	**19,793,409**	
Other Operating Expenses						
Depreciation Expense (403)		7,098,235		318,560	**7,416,795**	11
Amortization Limited-Term Utility Investment (404)		378,154		18,713	**396,867**	12
Amortization of Other Utility Plant (405)		52,903		2,317	**55,220**	13
Amortization of Utility Plant Acquisition Adjustment (406)					**0**	14
Amortization of Property Losses (407.1)					**0**	15
Amortization of Conversion Expenses (407.2)					**0**	16
Regulatory Debits (407.3)					**0**	17
(Less) Regulatory Credits (407.4)					**0**	18
Taxes Other Than Income Taxes (408.1)		2,356,691		88,393	**2,445,084**	19
Income Taxes (409.1)		(633,356)		(116,949)	**(750,305)**	20
Provision for Deferred Income Taxes (410.1, 411.1)		3,704,607		122,231	**3,826,838**	21
Accretion Expense FERC (411.10)					**0**	22
Investment Tax Credit Adjustment (411.4)		(25,629)		(1,206)	**(26,835)**	23
Total Other Operating Expenses	**0**	**12,931,605**	**0**	**432,059**	**13,363,664**	
Total Operating Expenses	**9,338,841**	**108,686,665**	**462,123**	**7,384,741**	**125,872,370**	

SALES OF GAS BY RATE SCHEDULE

1. Report data by rate schedule (including unbilled revenues and therms), classified between space heating and non-space heating customers and show totals for each account 480-484 incl.
2. Report average number of customers on basis of number of meters. Where meters are added for billing purposes, count one customer for each group of meters so added.
3. Compute averages on basis of 12 month end figures.
4. For industrial interruptible sales, report data by priority of interruption if not provided for by separate rate schedules.

Particulars (a)	Rate Schedule (b)	Average Number Customers (c)	Therms Sold (d)	Amount (e)	
Wisconsin Geographical Operations					
Residential Sales (480)					
Residential	201	89,271	62,438,420	61,297,767	1
Total Account 480:		**89,271**	**62,438,420**	**61,297,767**	
Commercial and Industrial Sales (481)					
Commercial	202 222	11,568	54,153,070	42,213,632	2
Industrial	203	1	856,460	1,132,007	3
Large Volume Interruptible	206 207	18	16,075,200	9,366,825	4
Small Volume Interruptible	206 207	234	10,748,080	6,453,231	5
Total Account 481:		**11,821**	**81,832,810**	**59,165,695**	
Sales for Resale (483)					
	NONE				6
Total Account 483:		**0**	**0**	**0**	
Interdepartmental Sales (484)					
	NONE				7
Firm Wisconsin	202	9	172,520	135,008	8
Interruptible Wisconsin	207	2	1,877,400	908,890	9
Other Wisconsin	NONE				10
Total Account 484:		**11**	**2,049,920**	**1,043,898**	
Total Sales of Gas		**101,103**	**146,321,150**	**121,507,360**	
Transportation (489)					
C&I Firm	202	3	12,238,350	251,395	11
C&I Interdepartmental Interruptible	207	1	1,681,830	(11,859)	12
C&I Interruptible	207	12	25,513,470	1,234,768	13
Total Account 489:		**16**	**39,433,650**	**1,474,304**	
Total Wisconsin		**101,119**	**185,754,800**	**122,981,664**	
Out-of-State Geographical Operations					
Residential Sales (480)					
	NONE				14
Residential	301	4,765	4,601,480	4,704,936	15
Total Account 480:		**4,765**	**4,601,480**	**4,704,936**	
Commercial and Industrial Sales (481)					
	NONE				16

SALES OF GAS BY RATE SCHEDULE

1. Report data by rate schedule (including unbilled revenues and therms), classified between space heating and non-space heating customers and show totals for each account 480-484 incl.
2. Report average number of customers on basis of number of meters. Where meters are added for billing purposes, count one customer for each group of meters so added.
3. Compute averages on basis of 12 month end figures.
4. For industrial interruptible sales, report data by priority of interruption if not provided for by separate rate schedules.

Particulars (a)	Rate Schedule (b)	Average Number Customers (c)	Therms Sold (d)	Amount (e)	
Out-of-State Geographical Operations					
Commercial and Industrial Sales (481)					
Commercial	302	636	2,829,400	2,671,225	**17**
Industrial	304	1	950,850	441,858	**18**
Large Volume Interruptible	304	1	175,850	91,419	**19**
Small Volume Interruptible	303	7	257,090	206,895	**20**
Total Account 481:		**645**	**4,213,190**	**3,411,397**	
Sales for Resale (483)					
	NONE				**21**
Total Account 483:		**0**	**0**	**0**	
Interdepartmental Sales (484)					
	NONE				**22**
Firm	302	3	10,120	9,991	**23**
Total Account 484:		**3**	**10,120**	**9,991**	
Total Sales of Gas		**5,413**	**8,824,790**	**8,126,324**	
Transportation (489)					
	NONE				**24**
Total Account 489:		**0**	**0**	**0**	
Total Out-of-State		**5,413**	**8,824,790**	**8,126,324**	
	TOTAL THROUGHPUT	**106,532**	**194,579,590**	**131,107,988**	

OTHER OPERATING REVENUES (GAS)

1. Report succinct statement of the revenues in each account and show separate totals for each account.
2. Report name of lessee and description of property for major items of rent revenue. Group other rents less than $25,000 by classes.
3. For sales of water and water power, report name of purchaser, purpose for which water used and the development supplying water.
4. Report basis of charges for any interdepartmental rents.
5. Report details of major items in Acct. 456. Group items less than $25,000.

Particulars (a)	Amount (b)	
Wisconsin Geographical Operations		
Forfeited Discounts (487):		
LATE PAYMENT CHARGES	295,434	1
Total Forfeited Discounts (487)	**295,434**	
Miscellaneous Service Revenues (488):		
SERVICE CONNECTIONS	217,625	2
RETURN CHECK CHARGE	5,324	3
MISCELLANEOUS	(34,972)	4
Total Miscellaneous Service Revenues (488)	**187,977**	
Revenues from Transportation of Gas of Others (489):		
FIRM TRANSPORTATION	251,395	5
INTERDEPARTMENTAL INTERRUPTIBLE TRANSPORTATION	(11,859)	6
INTERRUPTIBLE TRANSPORTATION	1,234,768	7
Total Revenues from Transportation of Gas of Others (489)	**1,474,304**	
Rent from Gas Property (493):		
NONE		8
Total Rent from Gas Property (493)	**0**	
Other Gas Revenues (495):		
SALES TAX HANDLING	8,973	9
PGA OVERRECOVERY	1,109,693	10
Total Other Gas Revenues (495)	**1,118,666**	
Penalty Revenue (497):		
NONE		11
Total Penalty Revenue (497)	**0**	
Utility Revenue Incentive (PBR) (498):		
NONE		12
Total Utility Revenue Incentive (PBR) (498)	**0**	
Total Wisconsin	**3,076,381**	
Out-of-State Geographical Operations		
Forfeited Discounts (487):		
LATE PAYMENT CHARGES	23,448	13
Total Forfeited Discounts (487)	**23,448**	
Miscellaneous Service Revenues (488):		
SERVICE CONNECTIONS	9,343	14
RETURN CHECK CHARGE	251	15
MISCELLANEOUS	(1,521)	16
Total Miscellaneous Service Revenues (488)	**8,073**	
Revenues from Transportation of Gas of Others (489):		
NONE		17
Total Revenues from Transportation of Gas of Others (489)	**0**	

OTHER OPERATING REVENUES (GAS)

1. Report succinct statement of the revenues in each account and show separate totals for each account.
2. Report name of lessee and description of property for major items of rent revenue. Group other rents less than $25,000 by classes.
3. For sales of water and water power, report name of purchaser, purpose for which water used and the development supplying water.
4. Report basis of charges for any interdepartmental rents.
5. Report details of major items in Acct. 456. Group items less than $25,000.

Particulars (a)	Amount (b)	
Out-of-State Geographical Operations		
Rent from Gas Property (493):		
NONE		18
Total Rent from Gas Property (493)	**0**	
Other Gas Revenues (495):		
SALES TAX HANDLING	345	19
GCR UNDERRECOVERY	(263,097)	20
Total Other Gas Revenues (495)	**(262,752)**	
Penalty Revenue (497):		
NONE		21
Total Penalty Revenue (497)	**0**	
Utility Revenue Incentive (PBR) (498):		
NONE		22
Total Utility Revenue Incentive (PBR) (498)	**0**	
Total Out-of-State	**(231,231)**	
TOTAL UTILITY	**2,845,150**	

GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
MANUFACTURED GAS PRODUCTION EXPENSES					
Operation Supervision and Engineering (710)			**0**	0	**1**
Steam Expenses (711)			**0**	0	**2**
Other Power Expenses (712)			**0**	0	**3**
Liquefied Petroleum Gas Expenses (717)			**0**	0	**4**
Liquefied Petroleum Gas (728)			**0**	0	**5**
Miscellaneous Production Expenses (735)	19,415	1,089,552	**1,108,967**	1,089,619	**6**
Rents (736)			**0**	0	**7**
Maintenance Supervision and Engineering (740)			**0**	0	**8**
Maintenance of Structures and Improvements (741)			**0**	0	**9**
Maintenance of Production Equipment (742)			**0**	0	**10**
Total Manufactured Gas Production Expenses	**19,415**	**1,089,552**	**1,108,967**	**1,089,619**	
NATURAL GAS PRODUCTION EXPENSES					
Rents (783)			**0**	0	**11**
Total Natural Gas Production Expenses	**0**	**0**	**0**	**0**	
OTHER GAS SUPPLY EXPENSES					
Natural Gas City Gate Purchases (804)	79,764	91,361,079	**91,440,843**	139,778,989	**12**
Liquefied Natural Gas Purchases (804.1)			**0**	0	**13**
Total Other Gas Supply Expenses	**79,764**	**91,361,079**	**91,440,843**	**139,778,989**	
GAS TRANSMISSION EXPENSES					
Other Gas Purchases (805)			**0**	0	**14**
Total Gas Transmission Expenses	**0**	**0**	**0**	**0**	
OTHER GAS SUPPLY EXPENSES					
Purchased Gas Cost Adjustments (805.1)			**0**	(1,241,798)	**15**
Incremental Gas Cost Adjustments (805.2)			**0**	0	**16**
Exchange Gas (806)			**0**	0	**17**
Purchased Gas Expenses (807)			**0**	0	**18**
Gas Withdrawn from Storage -- Debit (808.1)			**0**	0	**19**
(Less) Gas Delivered to Storage -- Credit (808.2)			**0**	0	**20**
Withdrawals of Liquefied Natural Gas held for Processing -- debit (809.1)			**0**	0	**21**
(Less) Deliveries of Natural Gas for Processing -- Credit (809.2)			**0**	0	**22**
(Less) Gas Used for Compressor Station Fuel -- Credit (810)			**0**	0	**23**
(Less) Gas Used for products Extraction -- Credit (811)			**0**	0	**24**
(Less) Gas Used for Other Utility Operations -- Credit (812)			**0**	0	**25**

GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
OTHER GAS SUPPLY EXPENSES					
Other Gas Supply Expenses (813)	104,018	61,469	**165,487**	89,841	**26**
Total Other Gas Supply Expenses	**104,018**	**61,469**	**165,487**	**(1,151,957)**	
OTHER STORAGE EXPENSES					
Operation Supervision and Engineering (840)	73,757	440	**74,197**	23,890	**27**
Operation Labor and Expenses (841)	8,518	106,315	**114,833**	208,297	**28**
Rents (842)		11,308	**11,308**	13,002	**29**
Fuel (842.1)			**0**	0	**30**
Power (842.2)			**0**	0	**31**
Gas Losses (842.3)			**0**	0	**32**
Maintenance Supervision and Engineering (843.1)			**0**	0	**33**
Maintenance of Structures and Improvements (843.2)			**0**	0	**34**
Maintenance of Gas Holders (843.3)			**0**	0	**35**
Maintenance of Purification Equipment (843.4)			**0**	0	**36**
Maintenance of Liquefaction Equipment (843.5)	5,115	4,393	**9,508**	19,102	**37**
Maintenance of Vaporizing Equipment (843.6)	7,033	6,103	**13,136**	4,328	**38**
Maintenance of Compressor Equipment (843.7)	5,085	38,899	**43,984**	21,155	**39**
Maintenance of Measuring and Regulating Station Equipment (843.8)	563	5,099	**5,662**	940	**40**
Maintenance of Other Equipment (843.9)	45,345	18,402	**63,747**	59,836	**41**
Total Other Storage Expenses	**145,416**	**190,959**	**336,375**	**350,550**	
TRANSMISSION EXPENSES					
Operation Supervision and Engineering (850)			**0**	0	**42**
System Control and Load Dispatching (851)			**0**	0	**43**
Communication System Expenses (852)			**0**	0	**44**
Compressor Station Labor and Expenses (853)			**0**	0	**45**
Gas for Compressor Station Fuel (854)			**0**	0	**46**
Other Fuel and Power for Compressor Stations (855)			**0**	0	**47**
Mains Expenses (856)			**0**	0	**48**
Measuring and Regulating Station Expenses (857)			**0**	0	**49**
Transmission and Compression of Gas by Others (858)			**0**	0	**50**
Other Expenses (859)			**0**	0	**51**
Rents (860)			**0**	0	**52**
Maintenance Supervision and Engineering (861)			**0**	0	**53**
Maintenance of Structures and Improvements (862)			**0**	0	**54**
Maintenance of Mains (863)			**0**	0	**55**
Maintenance of Compressor Station Equipment (864)			**0**	0	**56**
Maintenance of Measuring and Regulating Station Equipment (865)			**0**	0	**57**
Maintenance of Communication Equipment (866)			**0**	0	**58**

GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
TRANSMISSION EXPENSES					
Maintenance of Other Equipment (867)			**0**	0	**59**
Total Transmission Expenses	**0**	**0**	**0**	**0**	
DISTRIBUTION EXPENSES					
Operation Supervision and Engineering (870)	940,761	108,202	**1,048,963**	868,790	**60**
Distribution Load Dispatching (871)	94,737	346,378	**441,115**	446,416	**61**
Compressor Station Labor and Expenses (872)			**0**	0	**62**
Compressor Station Fuel and Power (873)			**0**	0	**63**
Mains and Services Expenses (874)	782,497	199,257	**981,754**	829,908	**64**
Measuring and Regulating Station Expenses--General (875)	217,925	84,003	**301,928**	282,552	**65**
Measuring and Regulating Station Expenses--Industrial (876)	47	1,625	**1,672**	5,044	**66**
Measuring and Regulating Station Expenses--City Gate Check Stations (877)	5,054	2,159	**7,213**	1,369	**67**
Meter and House Regulator Expenses (878)	378,438	(552,474)	**(174,036)**	121,876	**68**
Customer Installations Expenses (879)	402,308	25,525	**427,833**	425,488	**69**
Other Expenses (880)	766,061	1,195,594	**1,961,655**	1,687,734	**70**
Rents (881)		399,738	**399,738**	372,324	**71**
Maintenance Supervision and Engineering (885)	46,329	12,343	**58,672**	34,952	**72**
Maintenance of Structures and Improvements (886)			**0**	0	**73**
Maintenance of Mains (887)	316,512	242,605	**559,117**	614,283	**74**
Maintenance of Compressor Station Equipment (888)			**0**	0	**75**
Maintenance of Measuring and Regulating Station Equipment--General (889)	31,745	8,949	**40,694**	76,232	**76**
Maintenance of Measuring and Regulating Station Equipment--industrial (890)		1,428	**1,428**	391	**77**
Maintenance of Measuring and Reg. Station Equip.--City Gate Check Stations (891)	11,516	21,768	**33,284**	32,677	**78**
Maintenance of Services (892)	149,363	249,759	**399,122**	316,628	**79**
Maintenance of Meters and House Regulators (893)	376,958	66,294	**443,252**	374,662	**80**
Maintenance of Other Equipment (894)			**0**	0	**81**
Total Distribution Expenses	**4,520,251**	**2,413,153**	**6,933,404**	**6,491,326**	
CUSTOMER ACCOUNTS EXPENSES					
Supervision (901)	12,371	2,493	**14,864**	17,534	**82**
Meter Reading Expenses (902)	628,932	545,337	**1,174,269**	1,106,931	**83**
Customer Records and Collection Expenses (903)	690,314	845,790	**1,536,104**	1,470,128	**84**
Uncollectible Accounts (904)		1,141,640	**1,141,640**	1,378,505	**85**
Miscellaneous Customer Accounts Expenses (905)		103,853	**103,853**	102,162	**86**
Total Customer Accounts Expenses	**1,331,617**	**2,639,113**	**3,970,730**	**4,075,260**	
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
Supervision (907)			**0**	0	**87**
Customer Assistance Expenses (908)	367,347	2,948,795	**3,316,142**	3,150,137	**88**

GAS OPERATION AND MAINTENANCE EXPENSES

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES					
Informational and Instructional Advertising Expenses (909)		170,375	**170,375**	152,119	**89**
Miscellaneous Customer Service and Informational Expenses (910)			**0**	0	**90**
Total Customer Service and Informational Expenses	**367,347**	**3,119,170**	**3,486,517**	**3,302,256**	
SALES EXPENSES					
Supervision (911)			**0**	0	**91**
Demonstrating and Selling Expenses (912)	40,448	35,094	**75,542**	102,609	**92**
Advertising Expenses (913)			**0**	0	**93**
Miscellaneous Sales Expenses (916)			**0**	0	**94**
Total Sales Expenses	**40,448**	**35,094**	**75,542**	**102,609**	
ADMINISTRATIVE AND GENERAL EXPENSES					
Administrative and General Salaries (920)	1,251,599		**1,251,599**	953,185	**95**
Office Supplies and Expenses (921)	234	993,194	**993,428**	926,513	**96**
(Less) Administrative Expenses Transferred -- Credit (922)		253,896	**253,896**	231,067	**97**
Outside Services Employed (923)		239,990	**239,990**	332,044	**98**
Property Insurance (924)		138,385	**138,385**	110,845	**99**
Injuries and Damages (925)	99,740	174,141	**273,881**	231,648	**100**
Employee Pensions and Benefits (926)	1,841,045		**1,841,045**	1,297,614	**101**
Franchise Requirements (927)			**0**	0	**102**
Regulatory Commission Expenses (928)		222,001	**222,001**	190,077	**103**
(Less) Duplicate Charges -- Credit (929)		182,764	**182,764**	283,454	**104**
General Advertising Expenses (930.1)	70	58,477	**58,547**	63,019	**105**
Miscellaneous General Expenses (930.2)		55,304	**55,304**	60,307	**106**
Rents (931)		344,122	**344,122**	342,589	**107**
Maintenance of General Plant (935)		9,199	**9,199**	9,325	**108**
Total Administrative and General Expenses	**3,192,688**	**1,798,153**	**4,990,841**	**4,002,645**	
Total Operation and Maintenance Expenses	**9,800,964**	**102,707,742**	**112,508,706**	**158,041,297**	

DETAIL OF NATURAL GAS CITY GATE PURCHASES, ACCT. 804

Particulars (a)	Labor Expense (b)	Other Expense (c)	Total Expense (d)	Last Year Total (e)	
PURCHASED GAS EXPENSES					
Wages and Salaries (804.11)	79,764	1,326	**81,090**	55,274	**1**
Supplies and Expenses (804.12)			**0**	0	**2**
Miscellaneous Purchased Gas Expenses (804.13)			**0**	0	**3**
Gas Contract Reservation Fees (804.21)		415,398	**415,398**	391,165	**4**
Gas Contract Commodity Costs (804.22)		38,155,174	**38,155,174**	85,519,548	**5**
Spot Gas Commodity Costs (804.23)		24,273,799	**24,273,799**	42,888,932	**6**
Other Gas Purchases (804.24)		323,705	**323,705**	277,258	**7**
Gas Surcharges (804.25)			**0**	0	**8**
Financial Instruments Expenses (804.26)		3,201,524	**3,201,524**	3,435,614	**9**
Gas Purchase Miscellaneous Expenses (804.27)			**0**	0	**10**
Gas Costs for Opportunity Sales (804.28)		249,240	**249,240**	393	**11**
(Less) Purchased Gas Sold -- Credit (804.32)		249,240	**249,240**	393	**12**
(Less) Gas Commodity Cost Transferred to Storage -- Credit (804.33)		11,571,549	**11,571,549**	30,066,674	**13**
(Less) Gas Used in Utility Operations -- Credit (804.34)			**0**	0	**14**
(Less) Gas Used for Transmission Pumping & Compression -- Credit (804.35)		1,441,264	**1,441,264**	2,661,687	**15**
Total Purchased Gas Expenses	**79,764**	**53,358,113**	**53,437,877**	**99,839,430**	
TRANSMISSION EXPENSES					
Transmission Contract Reservation Fees (804.41)		10,612,878	**10,612,878**	10,140,843	**16**
Commodity Transmission Fees (804.42)		342,029	**342,029**	529,910	**17**
Gas Transmission Surcharges (804.43)			**0**	0	**18**
Gas Transmission Fuel Expense (804.44)		1,441,264	**1,441,264**	2,661,687	**19**
No-Notice Service Expenses (804.45)		16,485	**16,485**	40,227	**20**
Other Transmission Fees and Expenses (804.46)			**0**	0	**21**
Miscellaneous Transmission Expenses (804.48)			**0**	0	**22**
Penalties, Unauthorized Use and Overrun, Utility (804.49)			**0**	0	**23**
Penalties, Unauthorized Use and Overrun, End-User (804.51)			**0**	0	**24**
(Less) Transmission Services Sold -- Credit (804.52)		75,719	**75,719**	69,068	**25**
(Less) Gas Transmission Expenses Transferred to Storage -- Credit (804.53)		450,021	**450,021**	799,212	**26**
(Less) Gas Transmission Expense Used in Operations -- Credit (804.54)			**0**	0	**27**
Transmission Costs for Opportunity Sales (804.55)			**0**	0	**28**
Total Transmission Expenses	**0**	**11,886,916**	**11,886,916**	**12,504,387**	
STORAGE EXPENSES					
Storage Reservation Fees (804.61)		2,428,676	**2,428,676**	2,428,676	**29**
Stored Gas Costs for System Use (804.62)		23,687,374	**23,687,374**	25,006,496	**30**
Storage Penalties (804.63)			**0**	0	**31**
Stored Gas Costs for Opportunity Sales (804.64)			**0**	0	**32**
(Less) Storage Capacity Released or Sold -- Credit (804.72)			**0**	0	**33**
(Less) Stored Gas Sold -- Credit (804.73)			**0**	0	**34**
Total Storage Expenses	**0**	**26,116,050**	**26,116,050**	**27,435,172**	
Total Expenses - Account 804 - Excl Pipeline Refunds	**79,764**	**91,361,079**	**91,440,843**	**139,778,989**	
Pipeline Refunds (804.06)			**0**	0	**35**
Total Expenses - Account 804	**79,764**	**91,361,079**	**91,440,843**	**139,778,989**	

GAS UTILITY PLANT IN SERVICE

1. Report below the original cost of utility plant in service according to the prescribed accounts.
2. Corrections to prior entries for plant additions and retirements should be reported in columns (c) or (d) as appropriate.
3. If necessary, classify Account 106 according to prescribed accounts, on an estimated basis, and include in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the completed construction properly classified in column (c).
4. If there is a significant amount of plant retirements, which have not been classified by plant account at year end, a tentative distribution of such retirements, on an estimated basis, should be included in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the retired plant is properly classified in column (d).

Account (a)	Balance First of Year (b)	Additions During Year (c)	Retirements During Year (d)	
INTANGIBLE PLANT				
Organization (301)	0			1
Franchises and Consents (302)	0			2
Miscellaneous Intangible Plant (303)	0	74,115		3
Total Intangible Plant	**0**	**74,115**	**0**	
MANUFACTURED GAS PRODUCTION PLANT				
Land and Land Rights (304)	0			4
Structures and Improvements (305)	0			5
Boiler Plant Equipment (306)	0			6
Other Power Equipment (307)	0			7
Coke Ovens (308)	0			8
Producer Gas Equipment (309)	0			9
Water Gas Generating Equipment (310)	0			10
Liquefied Petroleum Gas Equipment (311)	0			11
Oil Gas generating equipment (312)	0			12
Generating Equipment--Other Processes (313)	0			13
Coal, Coke, and Ash Handling Equipment (314)	0			14
Catalytic Cracking Equipment (315)	0			15
Other Reforming Equipment (316)	0			16
Purification Equipment (317)	0			17
Residual Refining Equipment (318)	0			18
Gas Mixing Equipment (319)	0			19
Other Equipment (320)	0			20
Total Manufactured Gas Production Plant	**0**	**0**	**0**	
NATURAL GAS STORAGE & PROCESSING - OTHER STORAGE PLANT				
Land and Land Rights (360)	155,136			21
Structures and Improvements (361)	437,372	341,134		22
Gas Holders (362)	1,625,796			23
Purification Equipment (363)	284,581			24
Liquifaction Equipment (363.1)	137,507			25
Vaporizing Equipment (363.2)	1,032,390			26
Compressor Equipment (363.3)	352,464			27
Measuring and Regulating Equipment (363.4)	1,504			28
Other Equipment (363.5)	1,741,266			29
Total Natural Gas Storage & Processing - Other Storage Plant	**5,768,016**	**341,134**	**0**	

GAS UTILITY PLANT IN SERVICE (cont.)

5. Column (f) is used to report the reclassifications or transfers within utility plant accounts.
6. Upon final disposition of Account 102, classify the plant balances according to prescribed accounts and include in column (f). The amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., should be reported in column (e).
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount, submit supplementary information reporting subaccount plant detail conforming to the requirements of this schedule.
8. Leased plant recorded in Account 101.1 should be further classified to the prescribed plant accounts.
9. For each transaction recorded in Account 102, describe the plant purchased or sold, identify the counterparty and date of transaction.

Account (a)	Adjustments Increase or (Decrease) (e)	Transfers (f)	Balance End of Year (g)	
Organization (301)			0	1
Franchises and Consents (302)			0	2
Miscellaneous Intangible Plant (303)			74,115	3
	0	0	74,115	
Land and Land Rights (304)			0	4
Structures and Improvements (305)			0	5
Boiler Plant Equipment (306)			0	6
Other Power Equipment (307)			0	7
Coke Ovens (308)			0	8
Producer Gas Equipment (309)			0	9
Water Gas Generating Equipment (310)			0	10
Liquefied Petroleum Gas Equipment (311)			0	11
Oil Gas generating equipment (312)			0	12
Generating Equipment--Other Processes (313)			0	13
Coal, Coke, and Ash Handling Equipment (314)			0	14
Catalytic Cracking Equipment (315)			0	15
Other Reforming Equipment (316)			0	16
Purification Equipment (317)			0	17
Residual Refining Equipment (318)			0	18
Gas Mixing Equipment (319)			0	19
Other Equipment (320)			0	20
	0	0	0	
Land and Land Rights (360)			155,136	21
Structures and Improvements (361)			778,506	22
Gas Holders (362)			1,625,796	23
Purification Equipment (363)			284,581	24
Liquifaction Equipment (363.1)			137,507	25
Vaporizing Equipment (363.2)			1,032,390	26
Compressor Equipment (363.3)			352,464	27
Measuring and Regulating Equipment (363.4)			1,504	28
Other Equipment (363.5)			1,741,266	29
	0	0	6,109,150	

GAS UTILITY PLANT IN SERVICE

1. Report below the original cost of utility plant in service according to the prescribed accounts.
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3. If necessary, classify Account 106 according to prescribed accounts, on an estimated basis, and include in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the completed construction properly classified in column (c).
4. If there is a significant amount of plant retirements, which have not been classified by plant account at year end, a tentative distribution of such retirements, on an estimated basis, should be included in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the retired plant is properly classified in column (d).

Account (a)	Balance First of Year (b)	Additions During Year (c)	Retirements During Year (d)	
NATURAL GAS STORAGE & PROCESSING - BASE LOAD LNG TERMINALING AND PROCESSING PLNT				
Land and Land Rights (364.1)	0			30
Structures and Improvements (364.2)	0			31
LNG Processing Terminal Equipment (364.3)	0			32
LNG Transportation Equipment (364.4)	0			33
Measuring and Regulating Equipment (364.5)	0			34
Compressor Station Equipment (364.6)	0			35
Communication Equipment (364.7)	0			36
Other Equipment (364.8)	0			37
Total Natural Gas Storage & Processing - Base Load LNG Terminaling and Processing Plnt	**0**	**0**	**0**	
TRANSMISSION PLANT				
Land and Land Rights (365.1)	0			38
Rights-of-Way (365.2)	0			39
Structures and Improvements (366)	0			40
Mains (367)	0			41
Compressor Station Equipment (368)	0			42
Measuring and Regulating Station Equipment (369)	0			43
Communication Equipment (370)	0			44
Other Equipment (371)	0			45
Total Transmission Plant	**0**	**0**	**0**	
DISTRIBUTION PLANT				
Land and Land Rights (374)	5,688			46
Structures and Improvements (375)	0			47
Mains (376)	76,627,012	4,007,759	174,687	48
Compressor Station Equipment (377)	0			49
Meas. and Reg. Station Equipment - General (378)	1,742,727	319,481		50
Meas. and Reg. Station Equipment - Cty. Gate (379)	3,462,168			51
Services (380)	54,039,909	3,244,887	104,991	52
Meters (381)	25,101,951	2,324,042	109,929	53
Meter Installations (382)	0			54
House Regulators (383)	0			55
House Regulatory Installations (384)	0			56
Industrial Measuring and Regulating Station Equipment (385)	0			57
Other Property on Customers' Premises (386)	0			58
Other Equipment (387)	0			59
Asset Retirement Costs for Distribution Plant (388)	(153,156)			* 60
Total Distribution Plant	**160,826,299**	**9,896,169**	**389,607**	

GAS UTILITY PLANT IN SERVICE (cont.)

5. Column (f) is used to report the reclassifications or transfers within utility plant accounts.
6. Upon final disposition of Account 102, classify the plant balances according to prescribed accounts and include in column (f). The amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., should be reported in column (e).
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount, submit supplementary information reporting subaccount plant detail conforming to the requirements of this schedule.
8. Leased plant recorded in Account 101.1 should be further classified to the prescribed plant accounts.
9. For each transaction recorded in Account 102, describe the plant purchased or sold, identify the counterparty and date of transaction.

Account (a)	Adjustments Increase or (Decrease) (e)	Transfers (f)	Balance End of Year (g)		
Land and Land Rights (364.1)			0		30
Structures and Improvements (364.2)			0		31
LNG Processing Terminal Equipment (364.3)			0		32
LNG Transportation Equipment (364.4)			0		33
Measuring and Regulating Equipment (364.5)			0		34
Compressor Station Equipment (364.6)			0		35
Communication Equipment (364.7)			0		36
Other Equipment (364.8)			0		37
	0	0	0		
Land and Land Rights (365.1)			0		38
Rights-of-Way (365.2)			0		39
Structures and Improvements (366)			0		40
Mains (367)			0		41
Compressor Station Equipment (368)			0		42
Measuring and Regulating Station Equipment (369)			0		43
Communication Equipment (370)			0		44
Other Equipment (371)			0		45
	0	0	0		
Land and Land Rights (374)			5,688		46
Structures and Improvements (375)			0		47
Mains (376)			80,460,084		48
Compressor Station Equipment (377)			0		49
Meas. and Reg. Station Equipment - General (378)			2,062,208		50
Meas. and Reg. Station Equipment - Cty. Gate (379)			3,462,168		51
Services (380)			57,179,805		52
Meters (381)			27,316,064		53
Meter Installations (382)			0		54
House Regulators (383)			0		55
House Regulatory Installations (384)			0		56
Industrial Measuring and Regulating Station Equipment (385)			0		57
Other Property on Customers' Premises (386)			0		58
Other Equipment (387)			0		59
Asset Retirement Costs for Distribution Plant (388)			(153,156)	*	60
	0	0	170,332,861		

GAS UTILITY PLANT IN SERVICE

1. Report below the original cost of utility plant in service according to the prescribed accounts.
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3. If necessary, classify Account 106 according to prescribed accounts, on an estimated basis, and include in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the completed construction properly classified in column (c).
4. If there is a significant amount of plant retirements, which have not been classified by plant account at year end, a tentative distribution of such retirements, on an estimated basis, should be included in column (e). In subsequent years, show the reversal of these tentative distributions in column (e) as the retired plant is properly classified in column (d).

Account (a)	Balance First of Year (b)	Additions During Year (c)	Retirements During Year (d)	
GENERAL PLANT				
Land and Land Rights (389)	23,856			**61**
Structures and Improvements (390)	183,227	13,913		**62**
Office Furniture and Equipment (391)	99,734	25,702		**63**
Transportation Equipment (392)	1,584,622	293,182		**64**
Stores Equipment (393)	2,677		2,677	**65**
Tools, Shop and Garage Equipment (394)	1,455,006	57,911		**66**
Laboratory Equipment (395)	469,695			**67**
Power-Operated Equipment (396)	1,069,488	28,502		**68**
Communication Equipment (397)	648,367	4,989,898		**69**
Miscellaneous Equipment (398)	0			**70**
Other Tangible Property (399)	0			**71**
Asset Retirement Costs for General Plant (399.1)	0			**72**
Total General Plant	**5,536,672**	**5,409,108**	**2,677**	
Total for Accounts 101 and 106	**172,130,987**	**15,720,526**	**392,284**	
Gas Plant Purchased (102)	0			**73**
(Less) Gas Plant Sold (102)	0			**74**
Experimental Gas Plant Unclassified (103)	0			**75**
Total utility plant in service	**172,130,987**	**15,720,526**	**392,284**	

GAS UTILITY PLANT IN SERVICE (cont.)

5. Column (f) is used to report the reclassifications or transfers within utility plant accounts.
6. Upon final disposition of Account 102, classify the plant balances according to prescribed accounts and include in column (f). The amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., should be reported in column (e).
7. For Account 399, state the nature and use of plant included in this account and if substantial in amount, submit supplementary information reporting subaccount plant detail conforming to the requirements of this schedule.
8. Leased plant recorded in Account 101.1 should be further classified to the prescribed plant accounts.
9. For each transaction recorded in Account 102, describe the plant purchased or sold, identify the counterparty and date of transaction.

Account (a)	Adjustments Increase or (Decrease) (e)	Transfers (f)	Balance End of Year (g)	
Land and Land Rights (389)			23,856	61
Structures and Improvements (390)			197,140	62
Office Furniture and Equipment (391)			125,436	63
Transportation Equipment (392)			1,877,804	64
Stores Equipment (393)			0	65
Tools, Shop and Garage Equipment (394)			1,512,917	66
Laboratory Equipment (395)			469,695	67
Power-Operated Equipment (396)			1,097,990	68
Communication Equipment (397)			5,638,265	69
Miscellaneous Equipment (398)			0	70
Other Tangible Property (399)			0	71
Asset Retirement Costs for General Plant (399.1)			0	72
	0	0	10,943,103	
	0	0	187,459,229	
Gas Plant Purchased (102)			0	73
(Less) Gas Plant Sold (102)			0	74
Experimental Gas Plant Unclassified (103)			0	75
	0	0	187,459,229	

GAS UTILITY PLANT IN SERVICE

Gas Utility Plant in Service (Page G-07)

General footnotes

60. The current year adjustment to the Asset Retirement Cost is equal to the amount of increase or reduction of the Asset Retirement Obligation. When the current year adjustment to the Asset Retirement Obligation is negative and exceeds the existing balance in the Asset Retirement Cost account, the balance will become negative. Although the Asset Retirement Obligation liability itself will never have a negative balance, it is possible for the Asset Retirement Cost to have a negative balance.

GAS UTILITY PLANT IN SERVICE (cont.)

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ACCUMULATED PROVISION FOR DEPRECIATION - GAS

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (d)	Accruals During Year: Additional Amount (e)	
INTANGIBLE PLANT					
Organization (301)	0				**1**
Franchises and Consents (302)	0				**2**
Miscellaneous Intangible Plant (303)	0	Various	4,937		**3**
Total Intangible Plant	**0**		**4,937**	**0**	
MANUFACTURED GAS PRODUCTION PLANT					
Land and Land Rights (304)	0				**4**
Structures and Improvements (305)	0				**5**
Boiler Plant Equipment (306)	0				**6**
Other Power Equipment (307)	0				**7**
Coke Ovens (308)	0				**8**
Producer Gas Equipment (309)	0				**9**
Water Gas Generating Equipment (310)	0				**10**
Liquefied Petroleum Gas Equipment (311)	0				**11**
Oil Gas generating equipment (312)	0				**12**
Generating Equipment--Other Processes (313)	0				**13**
Coal, Coke, and Ash Handling Equipment (314)	0				**14**
Catalytic Cracking Equipment (315)	0				**15**
Other Reforming Equipment (316)	0				**16**
Purification Equipment (317)	0				**17**
Residual Refining Equipment (318)	0				**18**
Gas Mixing Equipment (319)	0				**19**
Other Equipment (320)	0				**20**
Total Manufactured Gas Production Plant	**0**		**0**	**0**	
NATURAL GAS STORAGE & PROCESSING - OTHER STORAGE PLANT					
Land and Land Rights (360)	0				**21**
Structures and Improvements (361)	357,138	2.720%	59,968		**22**
Gas Holders (362)	1,788,375	0.000%			**23**
Purification Equipment (363)	222,559	5.450%	15,506		**24**
Liquifaction Equipment (363.1)	137,507	0.000%			**25**
Vaporizing Equipment (363.2)	902,929	3.130%	32,365		**26**
Compressor Equipment (363.3)	313,753	2.750%	9,678		**27**
Measuring and Regulating Equipment (363.4)	1,504	0.000%			**28**
Other Equipment (363.5)	1,434,998	3.010%	52,489		**29**
Total Natural Gas Storage & Processing - Other Storage Plant	**5,158,763**		**170,006**	**0**	
NATURAL GAS STORAGE & PROCESSING - BASE LOAD LNG TERMINALING AND PROCESSING PLNT					
Land and Land Rights (364.1)	0				**30**
Structures and Improvements (364.2)	0				**31**
LNG Processing Terminal Equipment (364.3)	0				**32**
LNG Transportation Equipment (364.4)	0				**33**

ACCUMULATED PROVISION FOR DEPRECIATION - GAS (cont.)

Account (a)	Book Cost of Plant Retired (f)	Cost of Removal (g)	Salvage (h)	Adjustments Increase or (Decrease) (i)	Balance End of Year (j)	
301					0	1
302					0	2
303					4,937	3
	0	0	0	0	4,937	
304					0	4
305					0	5
306					0	6
307					0	7
308					0	8
309					0	9
310					0	10
311					0	11
312					0	12
313					0	13
314					0	14
315					0	15
316					0	16
317					0	17
318					0	18
319					0	19
320					0	20
	0	0	0	0	0	
360					0	21
361					417,106	22
362					1,788,375	23
363					238,065	24
363.1					137,507	25
363.2					935,294	26
363.3					323,431	27
363.4					1,504	28
363.5					1,487,487	29
	0	0	0	0	5,328,769	
364.1					0	30
364.2					0	31
364.3					0	32
364.4					0	33

ACCUMULATED PROVISION FOR DEPRECIATION - GAS

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (d)	Accruals During Year: Additional Amount (e)	
NATURAL GAS STORAGE & PROCESSING - BASE LOAD LNG TERMINALING AND PROCESSING PLNT					
Measuring and Regulating Equipment (364.5)	0				34
Compressor Station Equipment (364.6)	0				35
Communication Equipment (364.7)	0				36
Other Equipment (364.8)	0				37
Total Natural Gas Storage & Processing - Base Load LNG Terminaling and Processing Plnt	**0**		**0**	**0**	
TRANSMISSION PLANT					
Land and Land Rights (365.1)	0				38
Rights-of-Way (365.2)	0				39
Structures and Improvements (366)	0				40
Mains (367)	0				41
Compressor Station Equipment (368)	0				42
Measuring and Regulating Station Equipment (369)	0				43
Communication Equipment (370)	0				44
Other Equipment (371)	0				45
Total Transmission Plant	**0**		**0**	**0**	
DISTRIBUTION PLANT					
Land and Land Rights (374)	0				46
Structures and Improvements (375)	0				47
Mains (376)	34,921,161	2.890%	2,272,274		48
Compressor Station Equipment (377)	0				49
Meas. and Reg. Station Equipment - General (378)	1,070,950	3.590%	68,258		50
Meas. and Reg. Station Equipment - Cty. Gate (379)	1,702,152	3.670%	127,062		51
Services (380)	38,230,302	5.240%	2,912,045		52
Meters (381)	13,667,122	4.260%	1,115,315		53
Meter Installations (382)	0				54
House Regulators (383)	0				55
House Regulatory Installations (384)	0				56
Industrial Measuring and Regulating Station Equipment (385)	0				57
Other Property on Customers' Premises (386)	0				58
Other Equipment (387)	0				59
Asset Retirement Costs for Distribution Plant (388)	81,949	2.450%	(2,424)		60
Total Distribution Plant	**89,673,636**		**6,492,530**	**0**	
GENERAL PLANT					
Land and Land Rights (389)	0				61
Structures and Improvements (390)	162,633	3.090%	5,881		62
Office Furniture and Equipment (391)	99,735	Various	268		63
Transportation Equipment (392)	672,675	Various	157,175		64
Stores Equipment (393)	2,677	5.000%			65
Tools, Shop and Garage Equipment (394)	775,993	5.000%	73,299		66

ACCUMULATED PROVISION FOR DEPRECIATION - GAS (cont.)

Account (a)	Book Cost of Plant Retired (f)	Cost of Removal (g)	Salvage (h)	Adjustments Increase or (Decrease) (i)	Balance End of Year (j)	
364.5					**0**	**34**
364.6					**0**	**35**
364.7					**0**	**36**
364.8					**0**	**37**
	0	**0**	**0**	**0**	**0**	
365.1					**0**	**38**
365.2					**0**	**39**
366					**0**	**40**
367					**0**	**41**
368					**0**	**42**
369					**0**	**43**
370					**0**	**44**
371					**0**	**45**
	0	**0**	**0**	**0**	**0**	
374					**0**	**46**
375					**0**	**47**
376	174,687	46,602			**36,972,146**	**48**
377					**0**	**49**
378					**1,139,208**	**50**
379					**1,829,214**	**51**
380	104,991	269,749			**40,767,607**	**52**
381	109,929				**14,672,508**	**53**
382					**0**	**54**
383					**0**	**55**
384					**0**	**56**
385					**0**	**57**
386					**0**	**58**
387					**0**	**59**
388					**79,525**	**60**
	389,607	**316,351**	**0**	**0**	**95,460,208**	
389					**0**	**61**
390					**168,514**	**62**
391					**100,003**	**63**
392					**829,850**	**64**
393	2,677				**0**	**65**
394					**849,292**	**66**

ACCUMULATED PROVISION FOR DEPRECIATION - GAS

Report in column (e) additional depreciation expense authorized by Commission to be charged where tax depreciation allowances exceed book amounts.

Primary Plant Accounts (a)	Balance First of Year (b)	Straight Line Rate % Used (c)	Accruals During Year: Straight Line Amount (d)	Accruals During Year: Additional Amount (e)	
GENERAL PLANT					
Laboratory Equipment (395)	334,135	5.000%	23,485		**67**
Power-Operated Equipment (396)	475,071	Various	81,152		**68**
Communication Equipment (397)	89,777	10.000%	256,001		**69**
Miscellaneous Equipment (398)	0	5.000%			**70**
Other Tangible Property (399)	0				**71**
Asset Retirement Costs for General Plant (399.1)	0				**72**
Retirement Work in Progress	(531,594)	Various		*	**73**
Total General Plant	**2,081,102**		**597,261**	**0**	
Gas Plant Purchased (102)	0				**74**
(Less) Gas Plant Sold (102)	0				**75**
Experimental Gas Plant Unclassified (103)	0				**76**
Total accum. prov. for depreciation	**96,913,501**		**7,264,734**	**0**	

ACCUMULATED PROVISION FOR DEPRECIATION - GAS (cont.)

Account (a)	Book Cost of Plant Retired (f)	Cost of Removal (g)	Salvage (h)	Adjustments Increase or (Decrease) (i)	Balance End of Year (j)		
395					**357,620**		**67**
396					**556,223**		**68**
397					**345,778**		**69**
398					**0**		**70**
399					**0**		**71**
399.1					**0**		**72**
RWIP		(25,252)			**(506,342)**	*	**73**
	2,677	**(25,252)**	**0**	**0**	**2,700,938**		
102					**0**		**74**
102b					**0**		**75**
103					**0**		**76**
	392,284	**291,099**	**0**	**0**	**103,494,852**		

ACCUMULATED PROVISION FOR DEPRECIATION - GAS

Accumulated Provision for Depreciation - Gas (Page G-09)

General footnotes

Balance End of Year includes ($506,342) of gas retirement work in progress.

ACCUMULATED PROVISION FOR DEPRECIATION - GAS (cont.)

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GAS STORED (ACCOUNTS 117, 164.1, 164.2 AND 164.3)

1. If during the year, adjustment was made to the stored gas inventory (such as to correct cumulative inaccuracies of gas measurements), furnish in a footnote an explanation for the reason for the adjustment, the MCF and dollar amount of the adjustment, and account charged or credited.
2. Give in a footnote, a concise statement of the facts and the accounting performed with respect to any enroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
3. If the company uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals upon "base stock," or restoration of previous encroachment, including brief particulars of any such accounting during the year.
4. If the company has provided accumulated provision for stored gas, which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of FERC authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, and (e) a summary showing balance of accumulated provision and entries during the year.
5. Report pressure base of gas volumes as 14.73 psia at 60 Degrees F. (See Note 1)

Description (a)	Noncurrent (Acct. 117) (b)	Current (Acct. 164.1) (c)	LNG (Acct. 164.2) (d)	LNG (Acct. 164.3) (e)	Total (f)	
Balance at Beginning of Year	0	20,625,971	1,093,974	0	**21,719,945**	1
Gas Delivered to Storage		11,920,691	100,878		**12,021,569**	2
Gas Withdrawn from Storage (contra Account)		(23,241,273)	(334,772)		**(23,576,045)**	3
						4
Other Debits or Credits (Net)		0			**0**	5
Balance at End of Year	**0**	**9,305,389**	**860,080**	**0**	**10,165,469**	6
Therms		26,479,660	1,226,420		**27,706,080**	7
Amount per Therm	**0.000**	**0.351**	**0.701**	**0.000**	**0.367**	8

DETAIL OF STORED GAS ACCOUNT (ACCOUNT 164.1)

1. If during the year, adjustment was made to the stored gas inventory (such as to correct cumulative inaccuracies of gas measurements), furnish in a footnote an explanation for the reason for the adjustment, the MCF and dollar amount of the adjustment, and account charged or credited.
2. Give in a footnote, a concise statement of the facts and the accounting performed with respect to any enroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
3. If the company uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock" and the inventory basis and the accounting performed with respect to any encroachment of withdrawals upon "base stock," or restoration of previous encroachment, including brief particulars of any such accounting during the year.
4. If the company has provided accumulated provision for stored gas, which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of FERC authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, and (e) a summary showing balance of accumulated provision and entries during the year.
5. Report pressure base of gas volumes as 14.73 psia at 60 Degrees F. (See Note 1)

Description (a)	Commodity Storage Fees Acct. 164.11 (b)	Commodity Injection Fees Acct. 164.12 (c)	Commodity Withdrawal Fees Acct. 164.13 (d)	Other Storage Fees Acct. 164.14 (e)	Stored Gas Withdrawn Acct. 164.16 (f)	
Balance at Beginning of Year	0	36,000	0	0	0	1
Gas Delivered to Storage		62,835				2
Gas Withdrawn from Storage (contra Account)		(55,712)				3
Other Debits or Credits (Net)						4
Balance at End of Year	**0**	**43,123**	**0**	**0**	**0**	5
Therms		26,479,660				6
Amount per Therm	**0.000**	**0.002**	**0.000**	**0.000**	**0.000**	7

Description (a)	Gas Commodity Costs Transferred to Storage - Debit Acct. 164.33 (g)	Gas Transmission Expense Transferred to Storage - Debit Acct. 164.53 (h)	Stored Gas Withdrawn for System Use Acct. 164.62 (i)	Stored Gas Forfeited Acct. 164.63 (j)	Total Acct. 164.1 (k)	
Balance at Beginning of Year	20,085,928	504,043	0	0	20,625,971	8
Gas Delivered to Storage	11,473,058	384,798			**11,920,691**	9
Gas Withdrawn from Storage (contra Account)	(22,598,557)	(587,004)			**(23,241,273)**	10
Other Debits or Credits (Net)					**0**	11
Balance at End of Year	**8,960,429**	**301,837**	**0**	**0**	**9,305,389**	12
Therms	26,479,660	26,479,660			26,479,660	13
Amount per Therm	**0.338**	**0.011**	**0.000**	**0.000**	**0.351**	14

LIQUEFIED NATURAL GAS STORED (ACCT. 164.2 - 164.3)

Particulars (a)	Amount (b)	Amount Therms (c)	
Balance, beginning of year	1,093,974	1,367,220	1
Gas delivered to storage	100,878	313,160	2
Gas withdrawn from storage (debit account 808)	334,772	453,960	3
Other transactions or adjustments (explain): NONE			4
Balance, end of year	**860,080**	**1,226,420**	

LIQUEFIED NATURAL GAS STORAGE STATISTICS

Location of Plant (a)	Total Storage Capacity Therms (b)	Maximum Daily Capacity Therms (c)	Total Investment End of Year (d)	Maximum Day's Withdrawal (e)	Total Production Expense for Year (f)	
Eau Claire, WI	2,700,000	180,000	4,899,460			1
La Crosse, WI	1,300,000	4,080	903,485			2

GAS PRODUCTION STATISTICS

Location of Plant (a)	Type of Plant (b)	Maximum Daily Capacity Dekatherms (c)	Threms Produced During Year (d)	Total Investment End of Year (e)	Total Production Expense for Year (f)		
New Richmond, WI	Propane Air	4,080	0	98,875	0		1
Tomah, WI	Propane Air	0	0	207,330	0	*	2
		4,080	**0**	**306,205**	**0**		

GAS PRODUCTION STATISTICS

Gas Production Statistics (Page G-15)

General footnotes

2. The propane air plant is used only as a back-up supply to Fort McCoy.

GAS HOLDERS

	Telescopic & Piston Holders		Pressure Holders				
Location (a)	Number (b)	Capacity Therms (c)	Number (d)	Capacity at Atmospheric Pressure (e)	Design Pressure (f)	Operated Pressure (g)	
NONE							1

LIQUID PETROLEUM GAS STORAGE

Record hereunder number of liquid petroleum gas storage tanks and total capacity in gallons by location.

Location (a)	Number of Tanks (b)	Water Capacity (c)	
New Richmond, WI	1	25,500	1
Tomah, WI	3	30,600	2

PURCHASED GAS

Report below the specified information for each point of metering.

Name of Vendor (a)	Point of Metering (b)	Type of Gas Purchased (c)	Therms of Gas Purchased (d)	Total Cost of Gas Purchased (e)	
	Ashland, WI	Natural	7,815,310	0	**1**
	Bayfield, WI	Natural	1,142,880	0	**2**
	Bergland, MI	Natural	150,780	0	**3**
	Bessemer, MI	Natural	2,170,430	0	**4**
	BH Acres, WI	Natural	199,840	0	**5**
	Butternut, WI	Natural	230,910	0	**6**
	Chippewa Falls, WI	Natural	14,971,340	0	**7**
	Colfax, WI	Natural	16,878,870	0	**8**
	Control	Natural	0	91,361,079 *	**9**
	Eau Claire LNG	Natural	140,800	0	**10**
	Eau Claire, WI	Natural	27,026,740	0	**11**
	Ewen, MI	Natural	196,170	0	**12**
	Fall Creek, WI	Natural	596,910	0	**13**
	Fifield, WI	Natural	127,910	0	**14**
	Glidden, WI	Natural	272,830	0	**15**
	Hudson, WI	Natural	9,776,040	0	**16**
	Hurley, WI	Natural	1,350,290	0	**17**
	Iron River, WI	Natural	406,310	0	**18**
	Ironwood, MI	Natural	4,574,600	0	**19**
	Kinnickinnic, WI	Natural	1,884,180	0	**20**
	La Crosse, WI	Natural	51,725,100	0	**21**
	Marenisco, MI	Natural	362,570	0	**22**
	Mellen, WI	Natural	398,710	0	**23**
	Menomonie, WI	Natural	8,265,990	0	**24**
	Montreal, WI	Natural	381,170	0	**25**
	New Richmond, WI	Natural	6,833,680	0	**26**
	Ogema, WI	Natural	117,740	0	**27**
	Park Falls, WI	Natural	8,233,080	0	**28**
	Phillips, WI	Natural	3,039,800	0	**29**
	Prentice, WI	Natural	627,280	0	**30**
	Ramsey, MI	Natural	431,000	0	**31**
	Rib Lake, WI	Natural	524,070	0	**32**
	Saxon, WI	Natural	50,290	0	**33**
	Shelby, WI	Natural	1,514,290	0	**34**
	Tomah-Fort McCoy, WI	Natural	3,873,880	0	**35**
	Wakefield, MI	Natural	650,050	0	**36**
	Washburn, WI	Natural	1,335,950	0	**37**
	Westboro, WI	Natural	112,960	0	**38**
	Wheaton, WI	Natural	16,821,820	0	**39**
Total:			**195,212,570**	**91,361,079**	

PURCHASED GAS (cont.)

	Average Cost Per Therm of Gas Purchased (f)	Maximum Therms Purchased in One Day (g)	Date of Such Maximum Purchase (h)	Average BTU Content per Cubit Foot of Gas (i)		
	0.000	0		0.000		**1**
	0.000	0		0.000		**2**
	0.000	0		0.000		**3**
	0.000	0		0.000		**4**
	0.000	0		0.000		**5**
	0.000	0		0.000		**6**
	0.000	0		0.000		**7**
	0.000			0.000		**8**
	0.000	1,473,620	01/15/2009	0.000	*	**9**
	0.000	0		0.000		**10**
	0.000	0		0.000		**11**
	0.000	0		0.000		**12**
	0.000	0		0.000		**13**
	0.000	0		0.000		**14**
	0.000	0		0.000		**15**
	0.000	0		0.000		**16**
	0.000	0		0.000		**17**
	0.000	0		0.000		**18**
	0.000	0		0.000		**19**
	0.000	0		0.000		**20**
	0.000	0		0.000		**21**
	0.000	0		0.000		**22**
	0.000	0		0.000		**23**
	0.000	0		0.000		**24**
	0.000	0		0.000		**25**
	0.000	0		0.000		**26**
	0.000	0		0.000		**27**
	0.000	0		0.000		**28**
	0.000	0		0.000		**29**
	0.000	0		0.000		**30**
	0.000	0		0.000		**31**
	0.000	0		0.000		**32**
	0.000	0		0.000		**33**
	0.000	0		0.000		**34**
	0.000	0		0.000		**35**
	0.000	0		0.000		**36**
	0.000	0		0.000		**37**
	0.000	0		0.000		**38**
	0.000	0		0.000		**39**
	0.468					

PURCHASED GAS

Purchased Gas (Page G-18)

General footnotes

The cost of gas purchased by metering point is not available.

PURCHASED GAS (cont.)

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GAS MAINS

1. Report mains separately by pipe material, diameter and either within or outside Wisconsin.
2. Identify pipe material as: I (Cast Iron), S (Steel), P (Plastic), Cu (Copper), F (Fiberglass), or O (Other).
3. Explain all reported adjustments as a schedule footnote.
4. For main additions reported in column (e), as a schedule footnote:
   a. Explain how the additions were financed.
   b. If assessed against property owners, explain the basis of the assessments.
   c. If the assessments are deferred, explain.

Pipe Material (a)	Diameter in Inches (c)	Number of Feet: First of Year (d)	Added During Year (e)	Retired During Year (f)	Adjustments Increase or (Decrease) (g)	End of Year (h)		
Within Wisconsin								
Steel								
	2.000	1,041,761			(6,101)	**1,035,660**	*	1
	4.000	717,402			(7,728)	**709,674**	*	2
	8.000	472,550				**472,550**		3
	10.000	9,160			(2,100)	**7,060**	*	4
	12.000	74,958			(177)	**74,781**	*	5
	20.000	8,028				**8,028**		6
Total:		**2,323,859**	**0**	**0**	**(16,106)**	**2,307,753**		
Plastic								
	2.000	6,536,085			57,248	**6,593,333**	*	7
	4.000	1,975,820			21,136	**1,996,956**	*	8
	8.000	47,811				**47,811**		9
Total:		**8,559,716**	**0**	**0**	**78,384**	**8,638,100**		
Total Within Wisconsin		**10,883,575**	**0**	**0**	**62,278**	**10,945,853**		
Outside of Wisconsin								
Steel								
	2.000	263,029				**263,029**		10
	4.000	73,108				**73,108**		11
	8.000	50,210				**50,210**		12
	10.000	4,628				**4,628**		13
	20.000	187				**187**		14
Total:		**391,162**	**0**	**0**	**0**	**391,162**		
Plastic								
	2.000	211,279			7,215	**218,494**	*	15
	4.000	64,504				**64,504**		16
	8.000	7,200				**7,200**		17
Total:		**282,983**	**0**	**0**	**7,215**	**290,198**		
Total Outside of Wisconsin		**674,145**	**0**	**0**	**7,215**	**681,360**		
Total Utility		**11,557,720**	**0**	**0**	**69,493**	**11,627,213**		

GAS MAINS

Gas Mains (Page G-20)

General footnotes

Additions and retirements reflected in the adjustment column because data reported was based on a beginning and ending year totals for 2008.

Sizes are by range in the Plant Records.
Example: 2" and Under or 2" to 4"

GAS SERVICES

Number of services should include only those owned by utility.

Type/Size (a)	Total services first of year: Main to curb (b)	Total services first of year: On customers' premises (c)	Number added during year: Main to curb (d)	Number added during year: On customers' premises (e)		
Gas Services Located in Wisconsin						
Other						
1.500	91,078	90,284	1,129	1,129	*	1
2.000	485	464	18	18		2
3.000	57	57				3
4.000	42	39	2	2		4
6.000	2	2				5
8.000	2	2				6
Total Other:	**91,666**	**90,848**	**1,149**	**1,149**		
Total Within Wisconsin	**91,666**	**90,848**	**1,149**	**1,149**		
Gas Services Located Outside Wisconsin						
Other						
1.500	5,806	5,804	38	38	*	7
2.000	18	18				8
3.000	1	1				9
4.000	3	3				10
Total Other:	**5,828**	**5,826**	**38**	**38**		
Total Outside of Wisconsin	**5,828**	**5,826**	**38**	**38**		
Total Utility:	**97,494**	**96,674**	**1,187**	**1,187**		

GAS SERVICES (cont.)

Number retired during year		Adjustments during year		Total services end of year			
Main to curb (f)	On customers' premises (g)	Main to curb (h)	On customers' premises (i)	Main to curb (j)	On customers' premises (k)		
351	351			91,856	91,062	*	1
8	8			495	474		2
				57	57		3
				44	41		4
				2	2		5
				2	2		6
359	359	0	0	92,456	91,638		
359	359	0	0	92,456	91,638		
24	24			5,820	5,818	*	7
				18	18		8
				1	1		9
				3	3		10
24	24	0	0	5,842	5,840		
24	24	0	0	5,842	5,840		
383	383	0	0	98,298	97,478		

GAS SERVICES

Gas Services (Page G-21)

General footnotes

Data reported was not by type in 2004 only by size

1. Should be 1 1/2" and Under

7. Should be 1 1/2" and Under

GAS SERVICES (cont.)

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GAS METERS

Number of meters should include only those carried in Utility Plant Account 381.

Particulars (a)	Number End of Year (b)	
Diaphragmed meters (capacity at 1/2 inch water column pressure drop:		1
2,400 cu. ft. per hour or less	118,571	2
Over 2,400 cu. ft. per hour	80	3
Rotary meters	719	4
Orifice meters		5
Total end of year	**119,370**	6
		7
In stock	5,988	8
Locked meters on customers' premises	1,095	9
Regular meters in customers' use	112,204	10
Prepayment meters in customers' use		11
Meters in company use, included in Account 381	83	12
Total end of year (as above)	**119,370**	13
		14
No. of diaphragmed meters at end of year which compensate for temperature		15
Number of house regulators installed at end of year		16

GAS METERS

Gas Meters (Page G-23)

General footnotes

16. Regulators now combined with meters in account 381.

SUMMARY OF GAS ACCOUNT & SYSTEM LOAD STATISTICS

Particulars (a)	Total All Systems Therms (b)	Wisconsin Operations Therms (c)	Out of State Operations Therms (d)	
GAS ACCOUNT				1
Gas produced (gross):				2
Propane - air	**0**			3
Other gas	**0**			4
Total gas produced	**0**	**0**	**0**	5
Gas purchased:				6
Natural	**158,798,240**	151,854,844	6,943,396	7
Other gas	**0**			8
Total gas purchased	**158,798,240**	**151,854,844**	**6,943,396**	9
Add: Gas withdrawn from storage	**32,090,800**	30,687,641	1,403,159	10
Less: Gas delivered to storage	**34,987,780**	33,457,952	1,529,828	11
Total	**155,901,260**	**149,084,533**	**6,816,727**	12
Transport gas received	**39,311,310**	37,592,437	1,718,873	13
Total gas delivered to mains	**195,212,570**	**186,676,970**	**8,535,600**	14
Gas sold				15
Gas sold (incl. interdepartmental)	**155,145,940**	146,321,150	8,824,790	16
Gas used by utility	**237,420**	221,800	15,620	17
Transport gas delivered	**39,433,650**	39,433,650		18
Total	**194,817,010**	**185,976,600**	**8,840,410**	19
Gas unaccounted for	**395,560**	**700,370**	**(304,810)**	20
				21
SYSTEM LOAD STATISTICS				22
Maximum send-out in any one day	**1,473,620**	1,404,120	69,500	23
Date of such maximum		01/15/2009	01/15/2009	24
Maximum daily capacity:				25
Total manufactured-gas production capacity	**4,080**	4,080		26
Liquefied natural gas storage capacity	**180,000**	180,000		27
Maximum daily purchase capacity	**1,148,010**	1,148,010		28
Total maximum daily capacity	**1,332,090**	**1,332,090**	**0**	29
Monthly send-out:				30
January	**34,891,970**	33,297,180	1,594,790	31
February	**25,307,920**	24,070,910	1,237,010	32
March	**21,666,080**	20,576,610	1,089,470	33
April	**13,925,600**	13,239,770	685,830	34
May	**8,554,950**	8,197,940	357,010	35
June	**7,725,100**	7,497,890	227,210	36
July	**7,235,170**	7,043,410	191,760	37
August	**7,567,530**	7,372,870	194,660	38
September	**7,487,230**	7,261,860	225,370	39
October	**15,145,880**	14,461,630	684,250	40
November	**16,109,380**	15,400,580	708,800	41
December	**29,595,760**	28,256,320	1,339,440	42
Total send-out	**195,212,570**	**186,676,970**	**8,535,600**	43
Footnotes				44

SUMMARY OF GAS ACCOUNT & SYSTEM LOAD STATISTICS

Summary of Gas Account & System Load Statistics (Page G-24)

General footnotes

Information not available to report Maximum Daily Capacity by jurisdiction.

HIRSCHMAN-HERFINDAHL INDEX

The Hirschman-Herfindahl Index (HHI) is a measure of the degree to which competitors have entered utility markets. It is determined by summing the squared market percentages for a particular rate class. For example, if the utility sells 75% of the natural gas in a particular class, marketer A sells 20%, and marketer B sells 5%, the HHI for that class is:

$$75^2 + 20^2 + 5^2 = 5{,}625 + 400 + 25 = 6{,}050$$

If the utility sells all the natural gas in a class, the HHI for that class is 100 squared, or 10,000.

Class (a)	Schedules (b)	Hirschman-Herfindahl Index (c)	Is the Utility the Provider with the Largest Market Share? (d)	
Large General Service	Cg-3 / Ct-3	10,000	Yes	1
Residential	Rg-1/ Rt-1	10,000	Yes	2
Contract Demand	Lg-1/ Lt-1	10,000	No	3
Small Interrruptible	Ig-1/ It-1	10,000	Yes	4
Firm Commercial	Cg-1/ Ct-1, Cg-2 / Ct-2	9,984	Yes	5
Interdepartmental	Various	8,824	No	6
Large Interruptible	Ig-2 / It-2	2,339	No	7

GAS CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Ashland County	
Cities	
ASHLAND	3,416
MELLEN	327
Total Cities:	**3,743**
Villages	
BUTTERNUT	180
Total Villages:	**180**
Towns	
ASHLAND	4
GINGLES	46
JACOBS	263
MORSE	25
SANBORN	287
Total Towns:	**625**
Total Ashland County:	**4,548**
Bayfield County	
Cities	
BAYFIELD	499
WASHBURN	915
Total Cities:	**1,414**
Towns	
BARKSDALE	129
BAYFIELD	198
BAYVIEW	7
EILEEN	23
HUGHES	4
IRON RIVER	318
RUSSELL	298
WASHBURN	4
Total Towns:	**981**
Total Bayfield County:	**2,395**
Chippewa County	
Cities	
CHIPPEWA FALLS	4,353
EAU CLAIRE	484
Total Cities:	**4,837**
Villages	
LAKE HALLIE	583
Total Villages:	**583**
Towns	
EAGLE POINT	327
HALLIE	1,180

Chippewa County Towns	Customers End of Year (b)
LAFAYETTE	1,449
TILDEN	8
WHEATON	80
Total Towns:	**3,044**
Total Chippewa County:	**8,464**
Dunn County	
Cities	
MENOMONIE	4,143
Total Cities:	**4,143**
Villages	
COLFAX	2
ELK MOUND	244
Total Villages:	**246**
Towns	
COLFAX	16
ELK MOUND	8
MENOMONIE	415
RED CEDAR	261
TAINTER	577
Total Towns:	**1,277**
Total Dunn County:	**5,666**
Eau Claire County	
Cities	
ALTOONA	2,194
EAU CLAIRE	21,168
Total Cities:	**23,362**
Villages	
FALL CREEK	355
Total Villages:	**355**
Towns	
BRUNSWICK	122
LINCOLN	4
PLEASANT VALLEY	462
SEYMOUR	529
UNION	401
WASHINGTON	1,706
Total Towns:	**3,224**
Total Eau Claire County:	**26,941**
Iron County	
Cities	
HURLEY	788

GAS CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Location (a)	Customers End of Year (b)
Iron County	
Cities	
MONTREAL	440
Total Cities:	**1,228**
Towns	
CAREY	1
KIMBALL	57
PENCE	72
SAXON	56
Total Towns:	**186**
Total Iron County:	**1,414**
La Crosse County	
Cities	
LA CROSSE	17,374
ONALASKA	6,447
Total Cities:	**23,821**
Villages	
HOLMEN	3,055
Total Villages:	**3,055**
Towns	
BARRE	57
CAMPBELL	1,565
GREENFIELD	7
HOLLAND	338
MEDARY	274
ONALASKA	1,473
SHELBY	1,639
Total Towns:	**5,353**
Total La Crosse County:	**32,229**
Monroe County	
Towns	
LA FAYETTE	1 *
Total Towns:	**1**
Total Monroe County:	**1**
Price County	
Cities	
PARK FALLS	1,162
PHILLIPS	780
Total Cities:	**1,942**
Villages	
PRENTICE	270
Total Villages:	**270**

Location (a)	Customers End of Year (b)
Price County	
Towns	
EISENSTEIN	27
ELK	237
FIFIELD	119
HILL	6
LAKE	257
OGEMA	113
PRENTICE	30
WORCESTER	348
Total Towns:	**1,137**
Total Price County:	**3,349**
Saint Croix County	
Cities	
HUDSON	5,375
NEW RICHMOND	3,349
Total Cities:	**8,724**
Villages	
NORTH HUDSON	1,280
Total Villages:	**1,280**
Towns	
ERIN PRAIRIE	6
HUDSON	1,944
KINNICKINNIC	67
RICHMOND	457
STANTON	122
STAR PRAIRIE	72
TROY	271
WARREN	5
Total Towns:	**2,944**
Total Saint Croix County:	**12,948**
Taylor County	
Villages	
RIB LAKE	356
Total Villages:	**356**
Towns	
RIB LAKE	17
WESTBORO	86
Total Towns:	**103**
Total Taylor County:	**459**
Total Company:	**98,414**

GAS CUSTOMERS SERVED

Number of customers in each city, village and town supplied directly with service by reporting utility at end of year.

Gas Customers Served (Page G-26)

General footnotes

Monroe County, Town of Lafayette - Fort Mc Coy has 946 meters counted as 1 customer.

APPENDIX

The following items shall be attached to the completed report:

Notes to Financial Statements

Service Territory Maps

(For 2009 report:) If you normally complete any of the following schedules, please attach a copy:

- Electric Plant Leased to Others (FERC p. 213)
- Nonutility Property (FERC p. 221)
- Extraordinary Property Losses (FERC p. 230)
- Unrecovered Plant and Regulatory Study Costs (FERC p. 230)
- Depreciation and Amortization of Electric Plant (FERC pp. 336-337)
- Common Utility Plant and Expenses (FERC p. 356)
- Pumped Storage Generating Plant Statistics (Large Plants) (FERC pp. 408-409)

Other documentation you are requested to provide.

NOTES TO FINANCIAL STATEMENTS

1. Accounting Policies

Business and System of Accounts — NSP-Wisconsin is principally engaged in the generation, transmission, distribution and sale of electricity and in the purchase, transportation, distribution and sale of natural gas. NSP-Wisconsin is subject to regulation by the FERC and state utility commissions. All of NSP-Wisconsin's accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Basis of Accounting - The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). As required by the FERC, NSP-Wisconsin accounts for its investment in majority-owned subsidiaries using the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries as required by GAAP. Deferred taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net current or long-term assets and liabilities. Estimated removal costs for future removal obligations are classified as accumulated depreciation on the utility plant in the FERC presentation and regulatory liabilities in the GAAP presentation. Accounting for the investments in majority-owned subsidiaries on the equity method and classifying certain deferred income taxes as long-term assets or long-term liabilities, rather than in accordance with GAAP, have no effect on net income and no material effect on retained earnings. In 2007, NSP-Wisconsin adopted new guidance related to uncertainty in income taxes and unrecognized tax benefits. As a result of adopting the recognition and measurement provisions of the guidance for GAAP reporting, the amount of benefit recognized on the balance sheet may differ from the amount taken or expected to be taken in a tax return, resulting in unrecognized tax benefits. A liability is created for an unrecognized tax benefit or the amount of a net operating loss carryforward or amount refundable is reduced. The liability is recorded in accounts separate from the accounts established for accumulated deferred income taxes, as required by the guidance. Conversely, FERC reporting requires uncertainties from tax positions involving temporary differences to recorded in accounts established for accumulated deferred income taxes.

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by FERC presentation of:

($ in thousands)		
Net utility plant	$	108,829
Current assets		4,996
Current liabilities		10,088
Other long-term assets		(105,203)
Long-term debt and other long-term liabilities		(1,468)

NSP-Wisconsin reports its net margin (revenues less expenses) from trading activities as revenue for GAAP reporting but it reports revenues and expenses separately for FERC reporting. Income tax expense is shown as a component of operating expense in the FERC presentation, in contrast to its GAAP presentation as a below-the-line deduction from operating income. This classification difference has no impact on net income.

($ in thousands)		
Operating revenues	$	109,767
Operating expenses		82,846
Other income and deductions		(1,161)
Cash provided by operating activities		(197)
Cash used in investing activities		267
Cash used in financing activities		(98)

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. NSP-Wisconsin presents its revenue net of any excise or other fiduciary-type taxes or fees.

NSP-Wisconsin has various rate-adjustment mechanisms in place that currently provide for the recovery of natural gas and electric fuel costs, as well as purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, for any difference between the total amount collected under the clauses and the recoverable costs incurred. Where applicable, under governing state regulatory commission rate orders, fuel costs over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. A summary of significant rate adjustment mechanisms follows:

- NSP-Wisconsin's rates in Wisconsin include a cost-of-gas adjustment clause for purchased natural gas, but not for purchased electric energy or electric fuel. Requests can be made for recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, or an interim fuel-cost hearing process.
- NSP-Wisconsin sells firm power and energy in wholesale markets, which are regulated by the FERC. Rates for these sales include monthly wholesale fuel cost-recovery mechanisms.

Fair Value Measurements — NSP-Wisconsin presents cash equivalents, interest rate derivatives, and commodity derivatives at estimated fair value in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest to approximate fair value. Changes in the observed trading prices and liquidity of cash equivalents, including commercial paper and money market funds, are also monitored as additional support for determining fair value and losses are recorded in earnings if fair value falls below recorded cost. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, NSP-Wisconsin may use quoted prices for similar contracts, or internally prepared valuation models to determine fair value.

Types of and Accounting for Derivative Instruments — NSP-Wisconsin uses derivative instruments in connection with its utility commodity price and interest rate activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by *ASC 815 Derivatives and Hedging*, are recorded on the balance sheets at fair value as derivative instruments valuation. This includes certain instruments used to mitigate market risk for the utility operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification is dependent on the applicability of specific regulation.

Gains or losses on hedging transactions for natural gas purchased for resale are recorded as a component of natural gas costs and interest rate hedging transactions are recorded as a component of interest expense. NSP-Wisconsin is allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility.

Cash Flow Hedges — Qualifying hedging relationships are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge). The accounting for derivatives requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting. NSP-Wisconsin formally documents all hedging relationships in accordance with this guidance. The documentation includes, among other factors, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedging transaction. In addition, at inception and on a quarterly basis, NSP-Wisconsin formally assesses whether the derivative instruments being used are highly effective in offsetting changes in the cash flows of the hedged items.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction. NSP-Wisconsin discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. To test the effectiveness of hedges, a hypothetical hedge is used to mirror all the critical terms of the hedged transaction and the dollar-offset method is utilized to assess the effectiveness of the actual hedge at inception and on an ongoing basis. Gains and losses related to discontinued hedges that were previously deferred in OCI or deferred as a regulatory asset or liability will remain deferred until the hedged transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur, in which case associated deferred amounts are immediately recognized in current earnings.

Normal Purchases and Normal Sales — NSP-Wisconsin enters into contracts for the purchase and sale of commodities for use in their business operations. *ASC 815 Derivatives and Hedging* requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting as normal purchases or normal sales.

NSP-Wisconsin evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. For further discussion of NSP-Wisconsin's risk management and derivative activities, see Note 7 to the financial statements.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired is charged to accumulated depreciation and amortization. Regulatory obligations to incur removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use.

NSP-Wisconsin records depreciation expense related to its plant by using the straight-line method over the plant's useful life. Actuarial and semi-actuarial life studies are performed on a periodic basis and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, for the years ended Dec. 31, 2009 and 2008 was 3.5 percent.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Wisconsin's rate base for establishing utility service rates.

Environmental Costs — Environmental costs are recorded when it is probable NSP-Wisconsin is liable for the costs and the liability can be reasonably estimated. Costs may be deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

Estimated remediation costs, excluding inflationary increases, are recorded. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If several designated responsible parties exist, costs are estimated and recorded only for NSP-Wisconsin's expected share of the cost. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates are classified as a regulatory liability.

Legal Costs — Litigation accruals are recorded when it is probable NSP-Wisconsin is liable for the costs and the liability can be reasonably estimated. External legal fees related to settlements are expensed as incurred.

Income Taxes — NSP-Wisconsin accounts for income taxes using the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. NSP-Wisconsin defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. NSP-Wisconsin uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations, is considered.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the book depreciable lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which are summarized in Note12 to the financial statements. For more information on income taxes, see Note 5 to the financial statements.

NSP-Wisconsin follows the guidance in *ASC 740 Income Taxes* to measure and disclose uncertain tax positions that NSP-Wisconsin has taken or expects to take in its income tax returns. In accordance with this guidance, NSP-Wisconsin recognizes a tax position in its financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

NSP-Wisconsin reports interest and penalties related to income taxes within the other income and interest charges sections in the statements of income.

Xcel Energy and its subsidiaries, including NSP-Wisconsin, file federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by Xcel Energy, as parent of the Xcel Energy group, are allocated to the Xcel Energy subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy in connection with combined state filings. The holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company.

Use of Estimates — In recording transactions and balances resulting from business operations, NSP-Wisconsin uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, AROs, decommissioning, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate.

Cash and Cash Equivalents — NSP-Wisconsin considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

Inventory — All inventories are recorded at average cost.

Regulatory Accounting — NSP-Wisconsin accounts for certain income and expense items in accordance with *ASC 980 Regulated Operations*. Under this guidance:

- Certain costs, which would otherwise be charged to expense, are deferred as regulatory assets based on the expected ability to recover them in future rates; and
- Certain credits, which would otherwise be reflected as income, are deferred as regulatory liabilities based on the expectation they will be returned to customers in future rates.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. If restructuring or other changes in the regulatory environment occur, NSP-Wisconsin may no longer be eligible to apply this accounting treatment and may be required to eliminate such regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Wisconsin's results of operations in the period the write-off is recorded. See more discussion of regulatory assets and liabilities in Note 12 to the financial statements.

Deferred Financing Costs — Other assets included deferred financing costs, net of amortization, of approximately $2.9 million and $3.4 million at Dec. 31, 2009 and 2008, respectively. NSP-Wisconsin is amortizing these financing costs over the remaining maturity periods of the related debt.

Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of write-offs and an allowance for bad debts. NSP-Wisconsin establishes an allowance for uncollectible receivables based on a reserve policy that reflects its expected exposure to the credit risk of customers.

Renewable Energy Credits — RECs are marketable environmental commodities that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to RPSs enacted by those states that are encouraging construction and consumption of renewable energy, but can also be sold separately from the energy produced.

When RECs are acquired in the course of generation or purchase as a result of meeting load obligations, they are recorded as inventory at cost. RECs acquired for trading purposes are recorded as other investments and are also recorded at cost. The cost of RECs that are retired for compliance purposes is recorded as electric fuel and purchased power expense. The net margin on sales of RECs for trading purposes is recorded as electric utility operating revenues, net of any margin sharing requirements.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2009 through March 1, 2010, the date the financial statements were available for issuance. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Accounting Pronouncements

Recently Adopted

Business Combinations — In December 2007, the FASB issued new guidance on business combinations which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This new guidance is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity's fiscal year that begins on or after Dec. 15, 2008. NSP-Wisconsin implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its financial statements.

Noncontrolling Interests — Also in December 2007, the FASB issued new guidance on noncontrolling interests in financial statements which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the balance sheets within equity, but separate from the parent's equity; the amount of net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the statement of earnings; and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently as equity transactions. This new guidance was effective for fiscal years beginning on or after Dec. 15, 2008. NSP-Wisconsin implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its financial statements.

Derivatives and Hedging Disclosures — In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. The guidance amends and expands previous disclosure requirements for derivative instruments and hedging activities, including disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative contracts. This new guidance was effective for fiscal years and interim periods beginning after Nov. 15, 2008. NSP-Wisconsin implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its financial statements. For further discussion and the required disclosures, see Note 7 to the financial statements.

Interim Fair Value Disclosures — In April 2009, the FASB issued new guidance on interim disclosures about fair value of financial instruments which requires that disclosures regarding the fair value of financial instruments be included in interim financial statements. This new guidance was effective for interim periods ending after June 15, 2009. NSP-Wisconsin implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its financial statements.

Fair Value in Inactive Markets — Also in April 2009, the FASB issued new guidance for identifying market transactions that are not orderly and determining fair value when market trading activity has decreased significantly. The new guidance emphasizes that even if there has been a significant decrease in the volume and level of market activity for an asset or liability, fair value still represents the exit price in an orderly transaction between market participants. This new guidance was effective for interim and annual periods ending after June 15, 2009. NSP-Wisconsin implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its financial statements.

Other-Than-Temporary Impairments — Additionally in April 2009, the FASB issued new guidance on recognition and presentation of other-than-temporary impairments which changes the method for determining whether an other-than-temporary impairment exists for debt securities, and also requires additional disclosures regarding other-than-temporary impairments. This new guidance was effective for interim and annual periods ending after June 15, 2009. NSP-Wisconsin implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its financial statements.

Accounting Standards Codification — In June 2009, the FASB issued *Topic 105 — Generally Accepted Accounting Principles Amendments Based on Statement of Financial Accounting Standards No. 168 — The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (Accounting Standards Update (ASU) No. 2009-01)*, which updates the FASB ASC to state that the Codification is to be the single source of authoritative generally accepted accounting principles, other than the guidance put forth by the SEC. All other accounting literature not included in the Codification is to be considered non-authoritative. The updates to the Codification contained in ASU No. 2009-01 were effective for interim and annual periods ending after Sept. 15, 2009. NSP-Wisconsin implemented the guidance set forth by ASU No. 2009-01, recognizing the Codification as the single source of authoritative generally accepted accounting principles, other than the guidance put forth by the SEC, on July 1, 2009. The implementation did not have a material impact on NSP-Wisconsin's financial statements.

Postretirement Benefit Plans — In December 2008, the FASB issued new guidance on employers' disclosures about postretirement benefit plan assets. The guidance amends and expands previous disclosure requirements for plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, and information regarding fair value measurements. This new guidance was effective for disclosures for fiscal years ending after Dec. 15, 2009. NSP-Wisconsin implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its financial statements. For further discussion and the required disclosures, see Note 6 to the financial statements.

Fair Value of Liabilities — In August 2009, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Measuring Liabilities at Fair Value (ASU No. 2009-05)*, which updates the Codification with clarifications for measuring the fair value of liabilities. The liability-specific guidance includes clarifications and guidelines for using, when available, the most observable prices in active markets for identical liabilities or similar liabilities, or the prices of identical liabilities or similar liabilities traded as assets, rather than more complex and less observable valuation techniques and inputs such as those used in a present value model. The updates to the Codification contained in ASU No. 2009-05 were effective for interim and annual periods beginning after its August, 2009 issuance. NSP-Wisconsin implemented the guidance on Sept. 1, 2009, and the implementation did not have a material impact on its financial statements.

Recently Issued

Consolidation of Variable Interest Entities — In June 2009, the FASB issued new guidance on consolidation of variable interest entities. The guidance will significantly affect various elements of consolidation under existing accounting standards, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary. This new guidance is effective for interim and annual periods beginning after Nov. 15, 2009. NSP-Wisconsin does not expect the implementation of the guidance to have a material impact on its financial statements.

Fair Value Measurement Disclosures — In January 2010, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Improving Disclosures about Fair Value Measurements (ASU No. 2010-06)*, which will update the Codification to require new disclosures for assets and liabilities measured at fair value. The requirements include expanded disclosure of valuation methodologies for Level 2 and Level 3 fair value measurements, transfers in and out of Levels 1 and 2, and gross rather than net presentation of certain changes in Level 3 fair value measurements. The updates to the Codification contained in ASU No. 2010-06 are effective for interim and annual periods beginning after Dec. 15, 2009, except for requirements related to gross presentation of certain changes in Level 3 fair value measurements, which are effective for interim and annual periods beginning after Dec. 15, 2010. NSP-Wisconsin does not expect the implementation of the guidance to have a material impact on its financial statements.

3. Short-Term Borrowings

NSP-Wisconsin has an intercompany borrowing arrangement with NSP-Minnesota, with interest charged at NSP-Minnesota's short-term borrowing rate. NSP-Wisconsin has approval by the Board of Directors to issue up to $100 million under the arrangement. At Dec. 31, 2009, NSP-Wisconsin had short-term borrowings under this intercompany arrangement of $15.5 million with a weighted average interest rate of 0.36 percent. NSP-Wisconsin had no short-term borrowings at Dec. 31, 2008.

4. Long-Term Debt

In March 2009, NSP-Wisconsin redeemed its 7.375 percent $65.0 million first mortgage bonds due Dec. 1, 2026.

In September 2008, NSP-Wisconsin issued $200 million of 6.375 percent first mortgage bonds, series due Sept. 1, 2038. NSP-Wisconsin added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of such net proceeds to fund the payment at maturity of $80 million of 7.64 percent senior notes due Oct. 1, 2008. The balance of the net proceeds was used for the repayment of short-term debt (including notes payable to affiliates) and for general corporate purposes.

All property of NSP-Wisconsin is subject to the lien of its first mortgage indenture.

5. Income Taxes

Uncertainty in Income Taxes - The FERC has not fully adopted ASC 740. Accordingly, NSP-Wisconsin has recorded its unrecognized tax benefits for temporary adjustments in accounts established for accumulated deferred income taxes.

Federal Audit — NSP-Wisconsin is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. In 2008, the IRS completed an examination of Xcel Energy's federal income tax returns for 2004 and 2005 (and research credits for 2003). The IRS did not propose any material adjustments for those tax years. The statute of limitations applicable to Xcel Energy's 2004 and 2005 federal income tax returns expired on Dec. 31, 2009. The IRS commenced an examination of tax years 2006 and 2007 in 2008, and this audit is expected to be completed in the first quarter of 2010. As of Dec. 31, 2009, the IRS had not proposed any material adjustments to tax years 2006 and 2007.

State Audits — NSP-Wisconsin is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. As of Dec. 31, 2009, NSP-Wisconsin's earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2005. There currently are no state income tax audits in progress.

Unrecognized Tax Benefits — The amount of unrecognized tax benefits was $1.2 million and $1.5 million on Dec. 31, 2009 and Dec. 31, 2008, respectively. A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2009	2008
Balance at Jan. 1	$ 1.5	$ 0.9
Additions based on tax positions related to the current year	0.6	0.5
Reductions based on tax positions related to the current year	(0.1)	—
Additions for tax positions of prior years	0.3	0.1
Reductions for tax positions of prior years	(0.1)	—
Settlements with taxing authorities	(1.0)	—
Balance at Dec. 31	$ 1.2	$ 1.5

The tax benefits associated with net operating loss (NOL) and tax credit carryovers were not material as of Dec. 31, 2009 and Dec. 31, 2008.

The unrecognized tax benefit balance included $0.2 million and $0.2 million of tax positions on Dec. 31, 2009 and Dec. 31, 2008, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance included $1.0 million and $1.3 million of tax positions on Dec. 31, 2009 and Dec. 31, 2008, respectively, for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The decrease in the unrecognized tax benefit balance of $0.3 million in 2009 was due to the resolution of certain federal audit matters, partially offset by an increase due to the addition of similar uncertain tax positions related to ongoing activity. NSP-Wisconsin's amount of unrecognized tax benefits could significantly change in the next 12 months when the IRS and state audits resume. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change.

A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits is as follows:

(Millions of Dollars)	2009	2008
Payable for interest related to unrecognized tax benefits at Jan. 1	$ (0.1)	$ -
Interest income (expense) related to unrecognized tax benefits	0.1	(0.1)
Payable for interest related to unrecognized tax benefits at Dec. 31	$ -	$ (0.1)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2009 or Dec. 31, 2008.

Other Income Tax Matters — NOL and tax credit carryforwards as of Dec. 31, 2009 and 2008 were as follows:

(Millions of Dollars)	2009	2008
Federal NOL carryforward	3.7	3.2
Federal tax credit carryforwards	2.8	—

The federal carryforward periods expire between 2025 and 2029.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences for the years ending Dec. 31:

	2009	2008
Federal statutory rate	35.0%	35.0%
Increases (decreases) in tax form:		
State income taxes, net of federal income tax benefit	1.5	5.2
Tax credits recognized, net of federal income tax expense	(1.1)	(0.9)
Regulatory differences — utility plant items	(0.6)	(1.3)
Resolution of income tax audits and other	0.5	—
Change in unrecognized tax benefits	—	0.1
Other, net	(0.2)	(0.2)
Effective income tax rate	35.1%	37.9%

The components of NSP-Wisconsin's income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2009	2008
Current federal tax expense	$ 16,712	$ 20,177
Current state tax expense	1,232	6,332
Current change in unrecognized tax expense (benefit)	(22)	78
Deferred federal tax expense	8,442	2,393
Deferred state tax expense (benefit)	78	(557)
Deferred tax credits	(165)	—
Deferred investment tax credits	(634)	(629)
Total income tax expense	$ 25,643	$ 27,794

The components of deferred income tax at Dec. 31 were:

(Thousands of Dollars)	2009	2008
Deferred tax expense excluding items below	$ 7,721	$ 4,137
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	685	(2,252)
Tax expense allocated to other comprehensive income	(51)	(49)
Deferred tax expense	$ 8,355	$ 1,836

The components of net deferred tax liability (current and noncurrent) at Dec. 31 were:

(Thousands of Dollars)	2009	2008
Deferred tax liabilities:		
Difference between book and tax bases of property	$ 198,913	$ 181,327
Regulatory assets	50,216	38,515
Pension expense	23,052	23,275
Other	9,033	7,098
Total deferred tax liabilities	$ 281,214	$ 250,215
Deferred tax assets:		
Environmental remediation	$ 40,416	$ 27,688
Differences between book and tax bases of property	22,556	21,878

Regulatory liabilities	13,589	5,063
Employee benefits	7,140	6,897
Deferred investment tax credits	4,922	4,156
Tax credit carryforward	2,847	-
Rate refund	3,152	3,926
Net operating loss carryforward	1,924	1,618
Bad debts	1,888	1,868
Other	971	3,034
Total deferred tax assets	$ 99,405	$ 76,128
Net deferred tax liability	$ 181,809	$ 174,087

6. Benefit Plans and Other Postretirement Benefits

Pension and other postretirement benefit disclosures below generally represent Xcel Energy information unless specifically identified as being attributable to NSP-Wisconsin.

Xcel Energy, which includes NSP-Wisconsin, offers various benefit plans to its employees. At Dec. 31, 2009, NSP-Wisconsin had 405 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2010.

Effective Jan. 1, 2009, Xcel Energy and NSP-Wisconsin adopted new guidance on employers' disclosures about pension and postretirement benefit plan assets. The new guidance expands employers' disclosure requirements for benefit plan assets, including investment policies and strategies, major categories of plan assets, and information regarding fair value measurements consistent with the disclosures for entities' recurring fair value measurements prescribed by *ASC 820 Fair Value Measurements.*

ASC 820 Fair Value Measurements establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as common stocks listed by the New York Stock Exchange.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs, such as corporate bonds with pricing based on market interest rate curves and recent trades of similarly rated securities.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation, such as asset and mortgage backed securities, for which subjective risk-based adjustments to estimated yield and forecasted prepayments are significant inputs.

Pension Benefits

Xcel Energy, which includes NSP-Wisconsin, has several noncontributory, defined benefit pension plans that cover almost all employees. Benefits are based on a combination of years of service, the employee's average pay and social security benefits. Xcel Energy's and NSP-Wisconsin's policy is to fully fund the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws, into an external trust over time.

Xcel Energy and NSP-Wisconsin base the investment-return assumption on expected long-term performance for each of the investment types included in the pension asset portfolio and consider the actual historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The historical weighted average annual return for the past 20 years for the portfolio of pension investments is 8.98 percent, which is greater than the current assumption level. The pension cost determination assumes a forecasted mix of investment types over the long term. Investment returns in 2009 were above the assumed level of 8.50 percent while returns in 2008 and 2007 were below the assumed level of 8.75 percent. Xcel Energy and NSP-Wisconsin continually review pension assumptions. In 2010, Xcel Energy will use an investment-return assumption, of all pension plans in aggregate, of 7.79 percent.

The assets are invested in a portfolio according to Xcel Energy's and NSP-Wisconsin's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity, however, a higher weighting in equity investments can increase the volatility in the return levels achieved by pension assets in any year.

The following table presents the target pension asset allocation for 2009 and 2008:

	2009	2008
Domestic and international equity securities	24%	52%
Long duration fixed income securities	34	—
Short to intermediate term fixed income securities	19	25
Alternative investments	18	23
Cash	5	—
Total	100%	100%

In 2009, Xcel Energy and NSP-Wisconsin engaged J.P. Morgan's Pension Advisory Group to evaluate the allocation of the total assets in the master pension trust, taking into consideration the funded status of each individual pension plan. The investment strategy employed during 2009 is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of short-to-intermediate term and long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios, and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following table presents, for each of the fair value hierarchy levels, pension plan assets that are measured at fair value as of Dec. 31, 2009:

(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 221,971	$ —	$ 221,971
Short-term investments & money market securities	—	324,683	—	324,683
Derivatives	—	11,606	—	11,606
Government securities	—	94,949	—	94,949
Corporate bonds	—	522,403	—	522,403
Asset-backed & mortgage-backed securities	—	—	191,831	191,831
Common stock	89,260	—	—	89,260
Private equity investments	—	—	82,098	82,098
Commingled equity and bond funds	—	1,014,072	—	1,014,072
Real estate	—	—	66,704	66,704
Securities lending collateral obligation and other	—	(170,251)	—	(170,251)
Total	$ 89,260	$ 2,019,433	$ 340,633	$ 2,449,326

The following table presents the changes in Level 3 pension plan assets for the year ended Dec. 31, 2009:

(Thousands of Dollars)	Jan. 1, 2009	Realized and Unrealized Gains Gains (Losses)	Purchases, Issuances, and Settlements (net)	Dec. 31, 2009
Asset-backed & mortgage-backed securities	$ 244,008	$ 151,755	$ (203,932)	$ 191,831
Real estate	109,289	(43,207)	622	66,704
Private equity investments	81,034	(5,682)	6,746	82,098
Total	$ 434,331	$ 102,866	$ (196,564)	$ 340,633

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of Dollars)	2009	2008
Accumulated Benefit Obligation at Dec. 31	$ 2,676,174	$ 2,435,513
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 2,598,032	$ 2,662,759
Service cost	65,461	62,698
Interest cost	169,790	167,881
Plan amendments	(35,341)	—
Actuarial loss (gain)	223,122	(47,509)
Benefit payments	(191,433)	(247,797)
Obligation at Dec. 31	$ 2,829,631	$ 2,598,032
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 2,185,203	$ 3,186,273
Actual return (loss) on plan assets	255,556	(788,273)
Employer contributions	200,000	35,000
Benefit payments	(191,433)	(247,797)
Fair value of plan assets at Dec. 31	$ 2,449,326	$ 2,185,203
Funded Status of Plans at Dec. 31:		
Funded status	$ (380,305)	$ (412,829)
Noncurrent assets	—	15,612
Noncurrent liabilities	(380,305)	(428,441)
Net pension amounts recognized on balance sheets	$ (380,305)	$ (412,829)
NSP-Wisconsin Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 76,573	$ 65,172
Prior service cost	4,920	6,549
Total	$ 81,493	$ 71,721
Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Regulatory assets	$ 81,493	$ 71,121
Total	$ 81,493	$ 71,121
NSP-Wisconsin accrued benefit liability recorded	24,006	13,675
Measurement Date	Dec. 31, 2009	Dec. 31, 2008

Significant Assumptions Used to Measure Benefit Obligations:

Discount rate for year-end valuation	6.00%	6.75%
Expected average long-term increase in compensation level	4.00	4.00
Mortality table	RP 2000	RP 2000

At Dec. 31, 2009, Xcel Energy's pension plans, in the aggregate, had plan assets of $2.4 billion and projected benefit obligations of $2.8 billion. At Dec. 31, 2008, one of the pension plans had plan assets of $259.9 million, which exceeded projected benefit obligations of $244.3 million and all other plans in the aggregate had plan assets of $1.9 billion and projected benefit obligations of $2.4 billion.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding for 2008 through 2009 for the pension plans and are not expected to require cash funding in 2010.

Xcel Energy accelerated its planned 2010 contribution of $100 million based on available liquidity, bringing its total pension contributions to $200 million during 2009.

- Voluntary contributions were made to the PSCo Bargaining Pension Plan of $173 million in 2009 and $35 million in 2008.
- Voluntary contributions were made to the NCE Non-Bargaining Pension Plan of $27 million in 2009. No voluntary contributions were made to the plan during 2008.
- Pension funding contributions for 2011, which will be dependent on several factors including, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $100 million to $150 million.

Plan Amendments — The decrease in the projected benefit obligation for the plan amendment is due to a change in the average earnings calculation resulting from negotiations with the PSCo Bargaining Pension Plan.

Benefit Costs — The components of net periodic pension cost (credit) are:

(Thousands of Dollars)	2009	2008
Service cost	$ 65,461	$ 62,698
Interest cost	169,790	167,881
Expected return on plan assets	(256,538)	(274,338)
Amortization of prior service cost	24,618	20,584
Amortization of net loss	12,455	11,156
Net periodic pension cost (credit)	$ 15,786	$ (12,019)
NSP-Wisconsin:		
Net periodic pension benefit cost (credit) recognized	$ 559	$ (1,041)
Significant Assumptions Used to Measure Costs:		
Discount rate for year-end valuation	6.75%	6.25%
Expected average long-term increase in compensation level	4.00	4.00
Expected average long-term rate of return on assets	8.50	8.75

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2010 pension cost calculations will be 7.79 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including NSP-Wisconsin, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year.

Xcel Energy, which includes NSP-Wisconsin, also maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of operating cash flows.

Defined Contribution Plans

Xcel Energy and NSP-Wisconsin maintain 401(k) and other defined contribution plans that cover substantially all employees. The contributions for NSP-Wisconsin were approximately $0.9 million in 2009 and 2008.

Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Wisconsin, has a contributory health and welfare benefit plan that provides health care and death benefits to most Xcel Energy retirees. The former NCE discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. Employees of the former NCE who retired after 1998 are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In 1993, Xcel Energy and NSP-Wisconsin adopted accounting guidance regarding other non-pension postretirement benefits and elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs.

Plan Assets — Certain state agencies that regulate Xcel Energy's utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. Also, a portion of the assets contributed on behalf of non-bargaining retirees has been funded into a sub-account of the Xcel Energy pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

Xcel Energy and NSP-Wisconsin base investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. The assets are invested in a portfolio according to Xcel Energy's and NSP-Wisconsin's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

The following table presents, for each of the fair value hierarchy levels, postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2009:

(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 165,291	$ —	$ 165,291
Short term investments	—	2,226	—	2,226
Derivatives	—	5,937	—	5,937
Government securities	—	1,538	—	1,538
Corporate bonds	—	60,416	—	60,416
Asset-backed & mortgage-backed securities	—	—	55,371	55,371
Preferred stock	—	540	—	540
Registered investment companies (mutual funds)	—	89,296	—	89,296
Securities lending collateral obligation and other	—	4,074	—	4,074
Total	$ —	$ 329,318	$ 55,371	$ 384,689

The following table presents the changes in Level 3 postretirement benefit plan assets for the year ended Dec. 31, 2009:

(Thousands of Dollars)	Jan. 1, 2009	Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Settlements (net)	Dec. 31, 2009
Asset-backed & mortgage-backed securities	$ 78,693	$ 4,051	$ (27,373)	$ 55,371

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of Dollars)	2009	2008
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 794,597	$ 830,315
Service cost	4,665	5,350
Interest cost	50,412	51,047
Medicare subsidy reimbursements	3,226	6,178
Plan amendments	(27,407)	—
Plan participants' contributions	13,786	13,892
Actuarial gain	(47,446)	(46,827)
Benefit payments	(62,931)	(65,358)
Obligation at Dec. 31	$ 728,902	$ 794,597
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 299,566	$ 427,459
Actual return (loss) return on plan assets	72,101	(132,226)
Plan participants' contributions	13,786	13,892
Employer contributions	62,167	55,799
Benefit payments	(62,931)	(65,358)
Fair value of plan assets at Dec. 31	$ 384,689	$ 299,566
Funded Status of Plans at Dec. 31:		
Funded status	$ (344,213)	$ (495,031)
Current liabilities	(2,240)	(4,928)
Noncurrent liabilities	(341,973)	(490,103)
Net pension amounts recognized on balance sheets	$ (344,213)	$ (495,031)
NSP-Wisconsin Amounts Not Yet Recognized as Components of Net Periodic Cost:		
Net loss	$ 10,057	$ 14,982
Net prior service credit	(140)	—
Transition obligation	514	685
Total	$ 10,431	$ 15,667
Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Regulatory assets	10,431	15,667
Total	$ 10,431	$ 15,667
NSP-Wisconsin accrued benefit liability recorded	19,927	23,908
Measurement Date	Dec. 31, 2009	Dec. 31, 2008
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	6.00%	6.75%

Mortality table	RP 2000	RP 2000

Effective Dec. 31, 2009, Xcel Energy and NSP-Wisconsin reduced the initial medical trend assumption from 7.4 percent to 6.8 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached is three years. Xcel Energy and NSP-Wisconsin base the medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by the retiree medical plan.

A 1-percent change in the assumed health care cost trend rate would have the following effects on NSP-Wisconsin:

(Thousands of Dollars)		
1-percent increase in APBO components of Dec. 31, 2009	$	2,007
1-percent decrease in APBO components of Dec. 31, 2009		(1,699)
1-percent increase in service and interest components of the net periodic cost		185
1-percent decrease in service and interest components of the net periodic cost		(153)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy, which includes NSP-Wisconsin, contributed $62.2 million during 2009 and $55.6 million during 2008 and expects to contribute approximately $45.4 million during 2010.

Plan Amendments — The decrease in the projected benefit obligation for the plan amendment is due to a change in the medical experience rate resulting from negotiations with the PSCo Bargaining Postretirement Health Care Plan.

Benefit Costs — The components of net periodic postretirement benefit cost are:

(Thousands of Dollars)	2009	2008
Service cost	$ 4,665	$ 5,350
Interest cost	50,412	51,047
Expected return on plan assets	(22,775)	(31,851)
Amortization of transition obligation	14,444	14,577
Amortization of prior service cost	(2,726)	(2,175)
Amortization of net loss	19,329	11,498
Net periodic postretirement benefit cost	$ 63,349	$ 48,446
NSP-Wisconsin:		
Net periodic postretirement benefit cost recognized	$ 2,126	$ 2,011
Significant Assumptions Used to Measure Costs:		
Discount rate for year-end valuation	6.75%	6.25%
Expected average long-term rate of return on assets (before tax)	7.50	7.50

Projected Benefit Payments

The following table lists the projected benefit payments for the pension and postretirement benefit plans.

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2010	$ 238,929	$ 58,738	$ 4,901	$ 53,837
2011	230,833	60,202	5,184	55,018

2012	234,256	60,665	5,529	55,136
2013	237,817	60,785	5,841	54,944
2014	244,160	61,260	6,075	55,185
2015-2019	1,256,824	313,040	33,598	279,442

7. Derivative Instruments

Effective Jan. 1, 2009, NSP-Wisconsin adopted new guidance on disclosures about derivative instruments and hedging activities contained in *ASC 815 Derivatives and Hedging*, which requires additional disclosures regarding why an entity uses derivative instruments, the volume of an entity's derivative activities, the fair value amounts recorded to the balance sheet for derivatives, the gains and losses on derivative instruments included in the statement of income or deferred, and information regarding certain credit-risk-related contingent features in derivative contracts.

NSP-Wisconsin enters into derivative instruments, including forward contracts, futures, swaps and options, to reduce risk in connection with changes in interest rates and utility commodity prices. See additional information pertaining to the valuation of derivative instruments in Note 8 to the financial statements.

Interest Rate Derivatives — NSP-Wisconsin enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for a specific period. These derivative instruments are designated as cash flow hedges for accounting purposes.

At Dec. 31, 2009, the amount of accumulated other comprehensive income related to interest rate derivatives expected to be reclassified into earnings during the next 12 months is $0.1 million and will be reclassified as the related hedged interest rate transactions impact earnings. Accumulated other comprehensive losses related to interest rate derivatives reclassified into earnings during the year ended Dec. 31, 2009 were $0.1 million.

Commodity Derivatives — NSP-Wisconsin enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy and gas for resale.

At Dec. 31, 2009, NSP-Wisconsin had no commodity derivative contracts designated as cash flow hedges. However, as of Dec. 31, 2009, NPS-Wisconsin has entered into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging instruments. Changes in the fair value of these commodity derivative instruments are deferred as a regulatory asset or liability based on commission approved regulatory recovery mechanisms.

During the year ended Dec. 31, 2009, changes in the fair value of natural gas commodity derivatives resulted in $0.1 million of net gains, recognized as regulatory assets and liabilities. During 2009, settlement losses on natural gas commodity derivatives of $3.4 million were incurred subject to purchased natural gas cost recovery mechanisms, which capture derivative settlement gains and losses out of income as a regulatory asset or liability, as appropriate. During 2009, NSP-Wisconsin recognized $1.0 million of losses in earnings for settlement losses of natural gas commodity derivatives.

NSP-Wisconsin had no derivative instruments designated as fair value hedges during the year ended Dec. 31, 2009, and as such, had no gains or losses from fair value hedges or related hedged transactions for the period.

The following table shows the commodity derivatives recorded to derivative instruments valuation in the balance sheets:

	2009		2008	
(Thousands of Dollars)	**Derivative Instruments Valuation - Assets [(a)]**	**Derivative Instruments Valuation - Liabilities**	**Derivative Instruments Valuation - Assets [(a)]**	**Derivative Instruments Valuation - Liabilities**
Natural gas hedging derivative instruments	$ 613	$ 20	$ 2	$ 1,869

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying cash flow hedges on NSP-Wisconsin's accumulated other comprehensive income, included in the statements of common stockholder's equity and comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2009	2008
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (742)	$ (820)
After-tax net realized losses on derivative transactions reclassified into earnings	76	78
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$ (666)	$ (742)

At Dec. 31, 2009, commodity derivatives recorded to derivative instruments valuation included derivative contracts with gross notional amounts of approximately 2,053,000 MMBtu of natural gas. These amounts reflect the gross notional amounts of futures and forwards and are not reflective of net positions in the underlying commodities. Notional amounts for options are also included on a gross basis, but are weighted for the probability of exercise.

Credit Related Contingent Features — Contract provisions of the derivative instruments that NSP-Wisconsin enters into may require the posting of collateral or settlement of the contracts for various reasons, including if NSP-Wisconsin is unable to maintain its credit rating. If the credit rating of NSP-Wisconsin at Dec. 31, 2009 were downgraded below investment grade, no contracts underlying NSP-Wisconsin's derivative liabilities would require the posting of collateral or contract settlement upon the downgrade.

Certain of NSP-Wisconsin's derivative instruments are subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Wisconsin's ability to fulfill its contractual obligations is reasonably expected to be impaired. As of Dec. 31, 2009, NSP-Wisconsin had no collateral posted related to adequate assurance clauses in derivative contracts.

8. Financial Instruments

The estimated Dec. 31 fair values of NSP-Wisconsin's recorded financial instruments are as follows:

	2009		2008	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Other investments	$ 51	$ 51	$ 160	$ 160
Long-term debt, including current portion	367,327	392,460	432,092	438,050

The fair value of cash and cash equivalents, notes and accounts receivable and notes and accounts payable are not materially different from their carrying amounts. The fair value of NSP-Wisconsin's long-term debt is estimated based on the quoted market prices for the same or similar issues or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2009 and 2008. These fair value estimates have not been comprehensively revalued for purposes of these financial statements since that date and current estimates of fair values may differ significantly.

NSP-Wisconsin provides a guarantee for payment or performance under a specified agreement. As a result, NSP-Wisconsin's exposure under the guarantee is based upon the net liability under the specified agreement. The guarantee issued by NSP-Wisconsin limits the exposure of NSP-Wisconsin to a maximum amount stated in the guarantee. The guarantee requires no liability to be recorded, contains no recourse provisions and requires no collateral. On Dec. 31, 2009, NSP-Wisconsin had the following guarantee and exposure related to that guarantee:

Nature of Guarantee	Guarantee Amount	Current Exposure	Term or Expiration Date	Triggering Event Requiring Performance	Assets Held as Collateral
(Millions of Dollars)					
Guarantee of customer	1.0	0.5	Continuing	(a)	N/A

loans for the Farm
Rewiring Program

[a] The debtor becomes the subject of bankruptcy or other insolvency proceedings.

Letters of Credit

NSP-Wisconsin may use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2009 and 2008, there were no letters of credit outstanding.

9. Fair Value Measurements

Effective Jan. 1, 2008, NSP-Wisconsin adopted new guidance for recurring fair value measurements contained in *ASC 820 Fair Value Measurements and Disclosures* which provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. A hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value was established by this guidance. The three levels in the hierarchy and examples of each level are as follows:

> Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.
>
> Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs.
>
> Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation.

Fair value for commodity derivatives is determined based on observable prices for identical or similar forward contracts, or internally prepared option valuation models using observable forward curves and volatilities. NSP-Wisconsin continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of NSP-Wisconsin's own credit risk when determining the fair value of commodity derivative liabilities, the impact of considering credit risk was immaterial to the fair value of commodity derivative assets and liabilities presented in the balance sheets.

The following tables present, for each of these hierarchy levels, NSP-Wisconsin's assets and liabilities that are measured at fair value on a recurring basis:

	Dec. 31, 2009				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Counterparty Netting [a]	Net Balance
Commodity derivative assets	$ —	$ 608	$ —	$ 5	$ 613
Commodity derivative liabilities	—	15	—	5	20

	Dec. 31, 2008				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Counterparty Netting [a]	Net Balance
Commodity derivative assets	$ —	$ 2	$ —	$ —	$ 2
Commodity derivative liabilities	600	1,269	—	—	1,869

[a] *ASC 815 Derivatives and Hedging* permits the netting or receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A

master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

10. Rate Matters

Pending and Recently Concluded Regulatory Proceedings — PSCW

Base Rate

2008 Electric Rate Case — Nuclear Decommissioning Expenses — In January 2008, the PSCW issued the final order in NSP-Wisconsin's 2008 test year rate case. The PSCW's final order included recovery of $8.7 million of annual nuclear decommissioning expenses, subject to refund, in anticipation of potential decreases in NSP-Minnesota's decommissioning expenses.

In June 2009, the MPUC issued the final order in its review of NSP-Minnesota's 2009 nuclear plant decommissioning accrual, and as a result of that order, the Wisconsin retail jurisdiction's share of annual nuclear decommissioning expenses decreased to approximately $1.4 million, effective January 2009. The PSCW reviewed NSP-Wisconsin's nuclear decommissioning expenses in the context of the company's 2010 electric rate case, and reduced the NSP-Wisconsin's 2010 revenue requirements pursuant to the refund provision in the 2008 rate case order.

The June 2009 MPUC order also directed NSP-Minnesota to return to customers their contributions made to the external escrow-decommissioning fund for the Monticello nuclear plant. In NSP-Wisconsin's 2010 electric rate case the PSCW decided that NSP-Wisconsin should return the Wisconsin retail jurisdiction's share of these funds, with interest to customers in the next rate case. NSP-Wisconsin's share of these funds is approximately $5.9 million as of Dec. 31, 2009.

2010 Electric and Natural Gas Rate Case — In June 2009, NSP-Wisconsin filed an electric and gas rate case in Wisconsin seeking an increase in retail electric rates of $30.4 million, or 5.7 percent, and proposed no change in natural gas rates. The request was based on an ROE of 10.75 percent, an equity ratio of 53.12 percent, an electric rate base of $644 million, a gas rate base of $81 million and a 2010 forecasted test year. The request was comprised of a base rate increase of $45.1 million offset by projected fuel decreases of $14.7 million.

In December 2009, the PSCW approved an electric rate increase of approximately $6.4 million or 1.2 percent and no change in gas rates, based on a 10.4 percent ROE and a 52.30 percent equity ratio. The PSCW ordered NSP-Wisconsin to apply $6.4 million of the estimated 2009 fuel refund obligation to offset the rate increase. Lastly, the PSCW approved NSP-Wisconsin's request for a limited rate case reopener in 2011 to update certain costs that are billed to NSP-Wisconsin through the interchange agreement with NSP-Minnesota.

The base non-fuel adjustments made by the PSCW include: (1) adjustments to the ROE and equity ratio as discussed above; (2) reduced interchange agreement fixed charge billings; and (3) a disallowance of certain employee compensation expenses. In addition, the PSCW adjustments include a $9.1 million reduction for Prairie Island nuclear plant decommissioning and depreciation expense as a result of the 10-year life extension approved by the MPUC earlier this year. The PSCW approved NSP-Wisconsin's request to discontinue the practice of reducing rate base and common equity to account for appropriated retained earnings associated with certain hydro licenses.

A summary of the PSCW's adjustments is listed below:

Millions of Dollars	Request	PSCW Approved
Base non-fuel	$ 45.1	$ 35.8
Fuel	(14.7)	(20.3)
Prairie Island decommissioning	—	(9.1)
Rate increase	$ 30.4	$ 6.4

Other

2009 Electric Fuel Cost Recovery — NSP-Wisconsin's actual fuel and purchased power costs for 2009 were less than the amount authorized in rates, primarily due to lower load and lower market prices for fuel and purchased power. In April 2009, the PSCW determined fuel costs were outside the established variance ranges and set NSP-Wisconsin's electric rates subject to refund with interest, pending a full review of 2009 fuel costs.

The PSCW has not yet completed its review of NSP-Wisconsin's 2009 fuel costs. However, based on actual 2009 fuel costs, NSP-Wisconsin has established a liability of $18.5 million to reflect its expected 2009 fuel refund obligation. As noted above, the PSCW ordered NSP-Wisconsin to apply $6.4 million of the 2009 fuel refund obligation to offset the 2010 electric rate increase. NSP-Wisconsin filed an application with the PSCW in February 2010, requesting authorization to immediately refund the remainder of its 2009 fuel refund obligation to customers before the PSCW completes its review of actual 2009 fuel costs. If the PSCW review determines an additional refund is owed, the balance would be deferred and returned to customers in NSP-Wisconsin's next rate filing.

Pending and Recently Concluded Regulatory Proceedings — FERC

FERC Section 5 Rate Cases for Interstate Gas Pipelines — In November 2009, the FERC approved orders initiating rate investigations under Section 5 of the Natural Gas Act (NGA) against Northern Natural Gas Company (NNG) and Great Lakes Gas Transmission Company (GLGT). NSP-Minnesota and NSP-Wisconsin are together the largest customer on NNG, holding $41 million per year of maximum rate storage and transportation contracts.

According to the FERC orders, FERC staff concluded, based on a review of the financial information filed with the FERC by the pipelines, that each of the pipelines are substantially over-recovering their cost of service and earning excessive ROEs. The orders require the pipelines to file full cost and revenue studies, and the matters were set for hearing before an ALJ on an expedited basis. If the FERC orders the pipelines to reduce their transportation and storage rates, the rate reductions and any associated refunds would be reflected in the purchased gas and electric fuel cost adjustment mechanisms of the Xcel Energy utility subsidiaries.

Xcel Energy has filed an intervention as part of a group of similarly situated GLGT shippers in the GLGT Section 5 case, and filed to intervene individually in the NNG Section 5 rate case. The FERC ALJ conducted a pre-hearing conference on Jan. 12, 2010 and established the procedural schedule for the proceedings. If fully litigated, the Section 5 rate cases can be expected to go to hearings before the ALJ beginning Aug. 2, 2010. An initial decision must be issued by Nov. 11, 2010.

11. Commitments and Contingent Liabilities

Capital Commitments — As of Dec. 31, 2009, the estimated cost of the capital expenditure programs and other capital requirements of NSP-Wisconsin is approximately $135 million in 2010, $155 million in 2011 and $160 million in 2012. NSP-Wisconsin's capital forecast includes the following major project:

CapX 2020 — In 2006, CapX 2020, an alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest, including Xcel Energy, announced that it had identified several groups of transmission projects that proposed to be complete by 2020. Group 1 project investments are expected to total approximately $1.7 billion, with major construction targeted to begin in 2010 and ending three to five years later. Xcel Energy's investment is expected to be approximately $900 million depending on the route and configuration approved by the MPUC and the PSCW. Approximately 75 percent of the 2010 capital expenditures and return on investment for transmission projects are expected to be recovered under an NSP-Minnesota TCR tariff rider mechanism authorized by Minnesota legislation, as well as a similar TCR mechanism passed in South Dakota. Cost-recovery by NSP-Wisconsin is expected to occur through the biennial PSCW rate case process.

The capital expenditure programs of NSP-Wisconsin are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth regulatory decisions, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting NSP-Wisconsin's long-term energy needs. In addition, NSP-Wisconsin's ongoing evaluation of compliance with future requirements to install emission-control equipment and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

Fuel Contracts — NSP-Wisconsin has contracts providing for the purchase and delivery of a significant portion of its current coal and natural gas requirements. These contracts expire in various years between 2010 and 2032. In addition, NSP-Wisconsin may be required to pay additional amounts depending on actual quantities shipped under these agreements. As NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers, NSP-Wisconsin may seek deferred accounting treatment and future rate recovery of increased costs due to an emergency event, if that event causes fuel costs to exceed the amount included in rates on an annual basis by more than 2 percent.

The estimated minimum purchases for NSP-Wisconsin under these contracts as of Dec. 31, 2009, is as follows:

(Millions of Dollars)	2009
Coal	$ 16.9
Natural gas supply	25.4
Gas storage and transportation	101.1

Leases — NSP-Wisconsin leases a variety of equipment and facilities used in the normal course of business, which are accounted for as operating leases. Rental expense under operating lease obligations was approximately $1.9 million and$2.1 million for 2009 and 2008, respectively. The majority of rental expense is for one-year renewable leases.

Future commitments under operating leases are:

(Millions of Dollars)	
2010	$ 1.0
2011	1.3
2012	1.1
2013	1.0
2014	1.0
2015 and thereafter	7.4
Total	$ 12.8

Joint Operating System — The electric production and transmission system of NSP-Wisconsin is managed as an integrated system with that of NSP-Minnesota, jointly referred to as the NSP System. The electric production and transmission costs of the entire NSP system are shared by NSP-Minnesota and NSP-Wisconsin. A FERC approved agreement between the two companies, called the Interchange Agreement, provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $12.5 billion under the Price-Anderson amendment to the Atomic Energy Act of 1954, as amended. NSP-Minnesota has secured $300 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $12.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $117.5 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $17.5 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective Oct. 29, 2008. The next adjustment is due on or before Oct. 29, 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $15.2 million for business interruption insurance and $30.9 million for property damage insurance if losses exceed accumulated reserve funds.

Environmental Contingencies

NSP-Wisconsin has been, or is currently, involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, NSP-Wisconsin believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, NSP-Wisconsin is pursuing, or intends to pursue, recovery from other PRPs and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for NSP-Wisconsin, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, NSP-Wisconsin would be required to recognize an expense.

Site Remediation — NSP-Wisconsin must pay all or a portion of the cost to remediate sites where past activities of NSP-Wisconsin or other parties have caused environmental contamination. Environmental contingencies could arise from various situations including sites of former MGPs operated by NSP-Wisconsin, its predecessors, or other entities; and third party sites, such as landfills, to which NSP-Wisconsin is alleged to be a PRP that sent hazardous materials and wastes. At Dec. 31, 2009, the liability for the cost of remediating these sites was estimated to be $100.8 million, of which $5.7 million was considered to be a current liability.

MGP Sites

Ashland MGP Site — NSP-Wisconsin has been named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (Ashland site) includes property owned by NSP-Wisconsin, which was previously an MGP facility and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill, and an area of Lake Superior's Chequamegon Bay adjoining the park.

In September 2002, the Ashland site was placed on the National Priorities List. A final determination of the scope and cost of the remediation of the Ashland site is not currently expected until 2010. In October 2004, the state of Wisconsin filed a lawsuit in Wisconsin state court for reimbursement of past oversight costs incurred at the Ashland site between 1994 and March 2003 in the approximate amount of $1.4 million. The state also alleged a claim for forfeitures and interest. This litigation was resolved in the first quarter of 2009, and all costs paid to the state are expected to be recoverable in rates.

In 2009, the EPA issued its proposed remedial action plan (PRAP). The estimated remediation costs for the cleanup proposed by the EPA in the PRAP range between $94.4 million and $112.8 million. NSP-Wisconsin submitted comments to EPA in response to the PRAP, and indicated that it had serious concerns about the cleanup approach proposed by the EPA. It is expected that the EPA will select a final remedial action plan sometime in early 2010.

NSP-Wisconsin's potential liability, the actual cost of remediating the Ashland site and the time frame over which the amounts may be paid out are not determinable until the EPA selects a remediation strategy for the entire site and determines NSP-Wisconsin's level of responsibility. NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site. NSP-Wisconsin has recorded a liability of $97.5 million based upon the minimum of the range of remediation costs established by the PRAP, together with estimated outside legal, consultant and remedial design costs. NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site and has authorized recovery of similar remediation costs for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers.

In addition to potential liability for remediation, NSP-Wisconsin may also have potential liability for natural resource damages at the Ashland site. NSP-Wisconsin has recorded an estimate of its potential liability based upon its best estimate of potential exposure.

Asbestos Removal — Some of NSP-Wisconsin's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. NSP-Wisconsin's removal costs for asbestos are expected to be immaterial; therefore, no ARO was recorded. See additional discussion of AROs below. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

EPA GHG Endangerment Finding — On Dec. 7, 2009, in response to the U. S. Supreme Court's decision in *Massachusetts v. EPA*, 549 U. S. 497 (2007), the EPA issued its "endangerment" finding that GHG emissions endanger public health and welfare and that emissions from motor vehicles contribute to the GHGs in the atmosphere. This endangerment finding creates a mandatory duty for the EPA to regulate GHGs from light duty vehicles. The EPA has proposed to finalize GHG efficiency standards for light duty vehicles by spring 2010. Thereafter, the EPA anticipates phasing-in permit requirements and regulation of GHGs for large stationary sources, such as power plants, in calendar year 2011.

CAIR — In March 2005, the EPA issued the CAIR to further regulate SO_2 and NOx emissions. The objective of CAIR is to cap emissions of SO_2 and NOx in the eastern United States, including Wisconsin. In response to the decisions by the D.C. Circuit Court of Appeals vacating but reinstating CAIR while the EPA develops revised regulations, the EPA has indicated that a CAIR replacement rule will be proposed in early 2010 with finalization planned for early 2011.

As currently written, CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for SO_2, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO_2 and NOx that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap and trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA's proposed model program, or they can propose another method, which the EPA would need to approve.

For 2009, the NOx allowance costs for NSP-Wisconsin were $0.5 million. The estimated NOx allowance cost for 2010 is $0.4 million. Allowance cost estimates for NSP-Wisconsin are based on fuel quality and current market data. NSP-Wisconsin believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates.

CAMR — In March 2005, the EPA issued the CAMR, which regulated mercury emissions from power plants. In February 2008, the D. C. Circuit Court of Appeals vacated CAMR, which impacts federal CAMR requirements but not necessarily state-only rules. The EPA has agreed to finalize MACT emission standards for all hazardous air pollutants from electric utility steam generating units by November 2011 to replace CAMR. Xcel Energy, the parent company of NSP-Wisconsin, anticipates that the EPA will require affected facilities to demonstrate compliance within 18 to 36 months thereafter.

Wisconsin Mercury Rule — On Dec. 1, 2008, the Wisconsin mercury reduction rule took effect, which impacts NSP-Wisconsin's Bay Front plant. The rule applies to coal-fired utility boilers and requires that small coal-fired utility boilers, which include all three boilers at the Bay Front plant, must perform a top-down best available control technology (BACT) analysis for mercury by June 30, 2011, and limit mercury emissions to a level that is determined by the WDNR to be BACT by Jan. 1, 2015.

NSP-Wisconsin has proposed a gasifier project for boiler 5. If the gasifier project is implemented prior to 2015, that boiler will no longer be subject to this rule as long as the modification does not increase mercury emissions, and the boiler no longer burns coal. At that point, it will likely be subject to revised commercial and industrial boiler Maximum Achievable Control Technology (Boiler MACT) requirements. In addition, if the Boiler MACT is revised prior to 2015, boilers 1 and 2 will no longer be subject to this rule, and will need to comply with the Boiler MACT. As such, any cost estimates to comply with the Wisconsin mercury reduction rule are premature at this time.

Federal Clean Water Act — The federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. In July 2004, the EPA published phase II of the rule, which applies to existing cooling water intakes at steam-electric power plants. Several lawsuits were filed against the EPA in the United States Court of Appeals for the Second Circuit (Court of Appeals) challenging the phase II rulemaking. In January 2007, the Court of Appeals issued its decision and remanded the rule to the EPA for reconsideration. In June 2007, the EPA suspended the deadlines and referred any implementation to each state's best professional judgment until the EPA is able to fully respond to the remand. In April 2008, the U. S. Supreme Court granted limited review of the Court of Appeals' opinion to determine whether the EPA has the authority to consider costs and benefits in assessing BTA. On April 1, 2009, the U. S. Supreme Court issued a decision in *Entergy Corp. v. Riverkeeper, Inc.*, concluding that the EPA can consider a cost benefit analysis when establishing BTA. The decision overturned only one aspect of the Court of Appeals' earlier opinion, and gives the EPA the discretion to consider costs and benefits when it reconsiders its phase II rules. Until the EPA fully responds to the Court of Appeals' decision, the rule's compliance requirements and associated deadlines will remain unknown. As such, it is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time.

Asset Retirement Obligations

NSP-Wisconsin records future plant removal obligations as a liability at fair value with a corresponding increase to the carrying values of the related long-lived assets in accordance with *ASC 410 Asset Retirement and Environmental Obligations*. This liability will be increased over time by applying the interest method of accretion to the liability and the capitalized costs will be depreciated over the useful life of the related long-lived assets. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset.

Recorded ARO — NSP-Wisconsin recognized an ARO for the retirement costs of natural gas mains and for the removal of electric transmission and distribution equipment. The electric transmission and distribution ARO consists of many small potential obligations associated with polychlorinated biphenyls (PCBs), mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have many in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

A reconciliation of the beginning and ending aggregate carrying amounts of NSP-Wisconsin's AROs is shown in the table below for the 12 months ended Dec. 31, 2009 and Dec. 31, 2008, respectively:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2009	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2009
Electric plant						
Electric transmission and distribution	$ 29	$ —	$ —	$ 2	$ (5)	$ 26
Natural gas plant						
Gas transmission and distribution	56	—	—	4	—	60
Total liability	$ 85	$ —	$ —	$ 6	$ (5)	$ 86

NSP-Wisconsin revised electric transmission and distribution AROs due to revised estimates and end of life dates.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2008	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2008
Electric plant						
Electric transmission and distribution	$ 24	$ —	$ —	$ 1	$ 4	$ 29
Natural gas plant						

Gas transmission and distribution	2,878	—	—	72	(2,894)	56
Total liability	$ 2,902	$ —	$ —	$ 73	$ (2,890)	$ 85

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition of them. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on NSP-Wisconsin's financial position and results of operations.

Gas Trading Litigation

Arandell vs. e prime, Xcel Energy, NSP-Wisconsin et al. — e prime was a subsidiary of Xcel Energy Markets Holdings Inc., which is a wholly owned subsidiary of Xcel Energy. Among other things, e prime was in the business of natural gas trading and marketing. e prime has not engaged in natural gas trading or marketing activities since 2003. In February 2007, a complaint was filed alleging that NSP-Wisconsin, Xcel Energy and e prime, among others, engaged in fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. The plaintiffs seek a declaration that contracts for natural gas entered into between Jan. 1, 2000 and Oct. 31, 2002 are void that they are entitled to repayment for amounts paid for natural gas during that time period, and that treble damages are appropriate. The case was filed in the Wisconsin State Court (Dane County), and then removed to U. S. District Court for the Western District of Wisconsin. In June 2007, the plaintiffs filed a motion to remand the matter to state court, which was denied, and the matter was transferred by the Multi-District Litigation panel to Federal District Court Judge Pro in Nevada, who is the judge assigned to the Western Area Wholesale Natural Gas Antitrust Litigation. In July 2007, plaintiffs filed an amended complaint in Federal District Court in Nevada, which includes allegations against NRG, a former Xcel Energy subsidiary. In February 2008, the court denied the defendants' motions for summary judgment, granted plaintiffs' motion to conduct limited discovery, and in December 2009 allowed defendants to renew their summary judgment motions.

In late March 2009, *Newpage Wisconsin System Inc.* commenced a lawsuit in state court in Wood County, Wis. The allegations are substantially similar to *Arandell* and name several defendants, including Xcel Energy, e prime and NSP-Wisconsin. In September 2009, Plaintiffs moved to the Newpage and Arandell matters. Defendants have filed motions to dismiss and, as with *Arandell*, Xcel Energy, e prime and NSP-Wisconsin believe the allegations asserted against them are without merit and they intend to vigorously defend against the asserted claims.

Environmental Litigation

Carbon Dioxide Emissions Lawsuit — In 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U. S. District Court in the Southern District of New York against five utilities, including Xcel Energy, the parent company of NSP-Wisconsin, to force reductions in CO_2 emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO_2 emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO_2 emissions. On Sept. 19, 2005, the court granted a motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the U. S. Court of Appeals for the Second Circuit. On Sept. 21, 2009, the Court of Appeals issued an opinion reversing the lower court decision. On Nov. 5, 2009, the defendants, including Xcel Energy, filed a petition for rehearing and en banc review. It is uncertain when the Court of Appeals will respond to the petition.

Comer vs. Xcel Energy Inc. et al. — In 2006, Xcel Energy, the parent company of NSP-Wisconsin, received notice of a purported class action lawsuit filed in U. S. District Court in the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants' CO_2 emissions "were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina." Plaintiffs allege in support of their claim, several legal theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. Plaintiffs filed a notice of appeal to the U. S. Court of Appeals for the Fifth Circuit.

On Oct. 16, 2009, the U. S. Court of Appeals for the Fifth Circuit reversed the district court decision, in part, concluding that the plaintiffs pleaded sufficient facts to overcome the constitutional challenges that formed the basis for dismissal by the district court. On Nov. 27, 2009, defendants, including Xcel Energy, filed a petition for en banc review. It is uncertain when the Court of Appeals will respond to the petition.

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U. S. District Court for the Northern District of California against Xcel Energy, the parent company of NSP-Wisconsin, and 23 other utilities, oil, gas and coal companies. Plaintiffs claim that defendants' emission of CO_2 and other GHGs contribute to global warming, which is harming their village. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss on June 30, 2008. On Oct. 15, 2009, the U. S. District Court dismissed the lawsuit on constitutional grounds. On Nov. 5, 2009, plaintiffs filed a notice of appeal to the U. S. Court of Appeals for the Ninth Circuit.

Employment, Tort and Commercial Litigation

MGP Insurance Coverage Litigation — In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire and La Crosse, Wis. In lieu of participating in discussions, in October 2003, two of NSP-Wisconsin's insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. In November 2003, NSP-Wisconsin commenced suit in Wisconsin state court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Minnesota court enjoined NSP-Wisconsin from pursuing the Wisconsin litigation. The Wisconsin action remains in abeyance.

NSP-Wisconsin has reached settlements with 22 insurers, and these insurers have been dismissed from both the Minnesota and Wisconsin actions. NSP-Wisconsin has also reached settlements in principle with Ranger Insurance Company (Ranger), TIG Insurance Company (TIG), Royal Indemnity Company and Globe Indemnity Company.

In July 2007, the Minnesota state court issued a decision on allocation, reaffirming its prior rulings that Minnesota law on allocation should apply and ordering the dismissal, without prejudice, of 11 insurers whose coverage would not be triggered under such an allocation method. In September 2007, NSP-Wisconsin commenced an appeal in the Minnesota Court of Appeals challenging the dismissal of these carriers.

On Aug. 25, 2009, the Minnesota Court of Appeals affirmed the district court decision. NSP-Wisconsin subsequently filed a petition for review of this decision with the Minnesota Supreme Court. On Nov. 17, 2009, the Minnesota Supreme Court issued an order denying the petition. Defendants subsequently filed in the Wisconsin state court action a motion to dismiss, which NSP-Wisconsin intends to oppose. Oral arguments are set for March 5, 2010. It is unknown when the court will rule on this motion.

The PSCW has established a deferral process whereby clean-up costs associated with the remediation of former MGP sites are deferred and, if approved by the PSCW, recovered from ratepayers. Carrying charges associated with these clean-up costs are not subject to the deferral process and are not recoverable from ratepayers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers. None of the aforementioned lawsuit settlements are expected to have a material effect on NSP-Wisconsin's financial statements.

12. Regulatory Assets and Liabilities

NSP-Wisconsin's financial statements are prepared in accordance with the provisions of *ASC 980 Regulated Operations*, as discussed in Note 1 to the financial statements. Under this guidance, regulatory assets and liabilities can be created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of the business that is not rate regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of NSP-Wisconsin no longer allow for the application of regulatory accounting guidance under GAAP, NSP-Wisconsin would be required to recognize the write-off of regulatory assets and liabilities in its statements of income.

The components of unamortized regulatory assets and liabilities on the balance sheets of NSP-Wisconsin are:

(Thousands of Dollars)	See Note	Remaining Amortization Period	2009	2008
Regulatory Assets				
Environmental costs	1	Generally four to six years once actual expenditures are incurred	$ 95,054	$ 63,727
Pension and employee benefit obligations [(b)]	1	Various	91,363	86,595
Nuclear decommissioning costs		Two years	6,293	8,776
AFUDC recorded in plant [(a)]		Plant lives	9,143	8,619
State commission accounting adjustments [(a)]		Plant lives	3,770	3,882
Conservation programs		Up to two years	2,139	711
MISO Day 2 costs			—	3,041
Contract valuation adjustments			—	2,884
Other		Various	2,640	2,569
Total noncurrent regulatory assets			$ 210,402	$ 180,804
Regulatory Liabilities				
Wisconsin overrecovered fuel costs			18,493	75
Purchased gas over/under recovery			302	1,140
Investment tax credit deferrals			8,217	6,939
MISO Day 2 costs			171	-
MISO gain on retail gas derivatives			593	-
Gain on sale of emission allowances			183	333
Other			1,799	1,202
Total noncurrent regulatory liabilities			$ 29,758	$ 9,689

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.

(b) Includes the non-qualified pension plan.

13. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy, including NSP-Wisconsin. The services are provided and billed to each subsidiary in accordance with service agreements executed by each subsidiary. Costs are charged directly to the subsidiary, which uses the service whenever possible, and are allocated if they cannot be directly assigned.

The electric production and transmission costs of the entire NSP system are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

The table below contains significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Thousands of Dollars)	2009	2008
Operating revenues		
Electric	$ 0	$ 0

Operating expenses		
Purchased power	289,189	293,750
Transmission expense	(9,417)	(9,970)
Natural gas purchased for resale	309	312
Other operations paid to Xcel Energy Services Inc	48,477	45,765
Interest expense	59	1,040

Accounts receivable and payable with affiliates at Dec. 31 were:

	2009		2008	
(Thousands of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$ —	$ 31,243	$ —	$ 12,416
PSCo	—	30	—	71
SPS	—	29	—	58
Other subsidiaries of Xcel Energy	20,449	7,412	600	5,055
	$ 20,449	$ 38,714	$ 600	$ 17,600

NSP-Wisconsin obtains short-term borrowings from NSP-Minnesota at NSP-Minnesota's average daily interest rate, including the cost of NSP-Minnesota's compensating balance requirements. At Dec. 31, 2009 and 2008, NSP-Wisconsin had notes payable outstanding to NSP-Minnesota in the amount of $15.5 million and $0.0 million, respectively.

14. Supplementary Cash Flow Data

(Thousands of Dollars)	Year Ended Dec. 31, 2009	Year Ended Dec. 31, 2008
Cash paid for interest (net of amounts capitalized)	$ (23,011)	$ (20,391)
Cash paid for income taxes (net of refunds received)	(30,046)	(15,804)
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 1,800	$ 2,017

15. Investments Accounted for by the Equity Method

Under FERC regulations, NSP-Wisconsin's investment in and income from its wholly-owned subsidiaries are presented using the equity method of accounting, rather than the GAAP method of consolidation. NSP-Wisconsin's subsidiaries are:

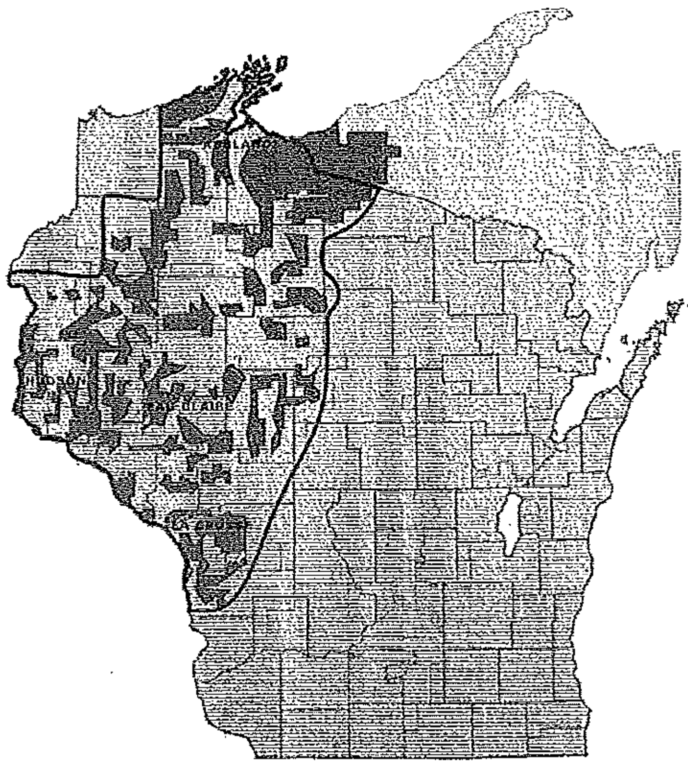
	Geographic Area	Percent voting stock owned
Chippewa and Flambeau Improvement Co.	USA	78.28%
Clearwater Investments, Inc.	USA	100%
NSP Lands, Inc.	USA	100%

Summarized Financial Information of Unconsolidated Investees – Summarized financial information for all equity-method subsidiaries:

Financial Position	2009	2008	Results of Operations	2009	2008
Current Assets	$ 778	$ 745	Operating Revenues	$ 1,310	$ 1,225
Other Assets	5,418	5,637	Operating Income	$ 249	$ 186

Total Assets	$ 6,196	$ 6,382	Net Loss	$ 30	$ 21
Current Liabilities	$ (2,070)	$ (962)			
Other Liabilities	(906)	(2,131)			
Equity	(3,220)	(3,289)			
Total Liabilities and Equity	$ (6,196)	$ (6,382)			

Xcel Energy®



ELECTRIC SERVICE TERRITORY-COUNTIES SERVED

*Xcel Energy offices located in cities listed below

WISCONSIN ELECTRIC SERVICE TERRITORY - COUNTIES SERVED

Ashland County
*Ashland

Barron County
*Rice Lake

Bayfield County
*Bayfield

Chippewa County
*Chippewa Falls

Clark County
*Neillsville

Crawford County

Dunn County
*Menomonie

Eau Claire County
*Eau Claire

Iron County

Jackson County

La Crosse County
*La Crosse

Lincoln County

Marathon County

Monroe County
*Sparta

Oneida County

Pepin County
*Durand

Pierce County

Polk County
*St. Croix Falls

Price County

Rusk County

St. Croix County
*Hudson

Sawyer County
*Hayward

Taylor County

Trempealeau County

Vernon County

Vilas County

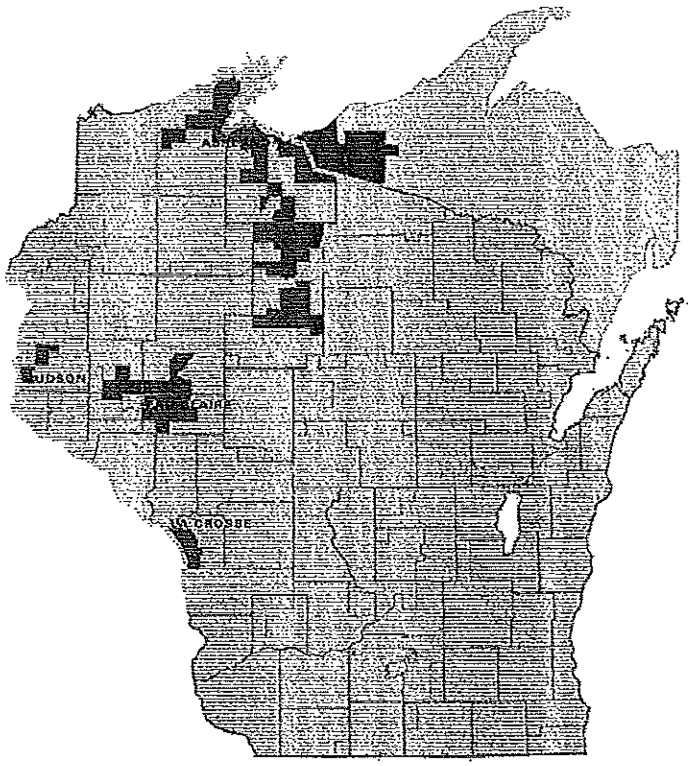
Washburn County

MICHIGAN ELECTRIC SERVICE TERRITORY - COUNTIES SERVED

Gogebic County
*Ironwood

Ontonagon County

Xcel Energy



NATURAL GAS TERRITORY-COMMUNITIES SERVED

WISCONSIN NATURAL GAS SERVICE TERRITORY

Ashland County
Ashland, Butternut, Gingles, Jacobs, Mellen, Morse, Sanborn

Bayfield County
Barksdale, Bayfield, Bayview, Eileen, Hughes, Iron River, Russell, Washburn

Chippewa County
Chippewa Falls, Eagle Point, Eau Claire, Hallie, Lafayette, Wheaton

Dunn County
Elk Mound, Menomonie, Red Cedar, Tainter

Eau Claire County
Altoona, Brunswick, Eau Claire, Fall Creek, Lincoln, Pleasant Valley, Seymour, Union, Washington

Iron County
Carey, Hurley, Kimball, Montreal, Pence, Saxon

La Crosse County
Campbell, Greenfield, Holland, Holmen, Medary, La Crosse, Onalaska, Shelby

Monroe County
Fort McCoy

Price County
Eisenstein, Elk, Fifield, Hill, Lake, Ogema, Park Falls, Phillips, Prentice, Worcester

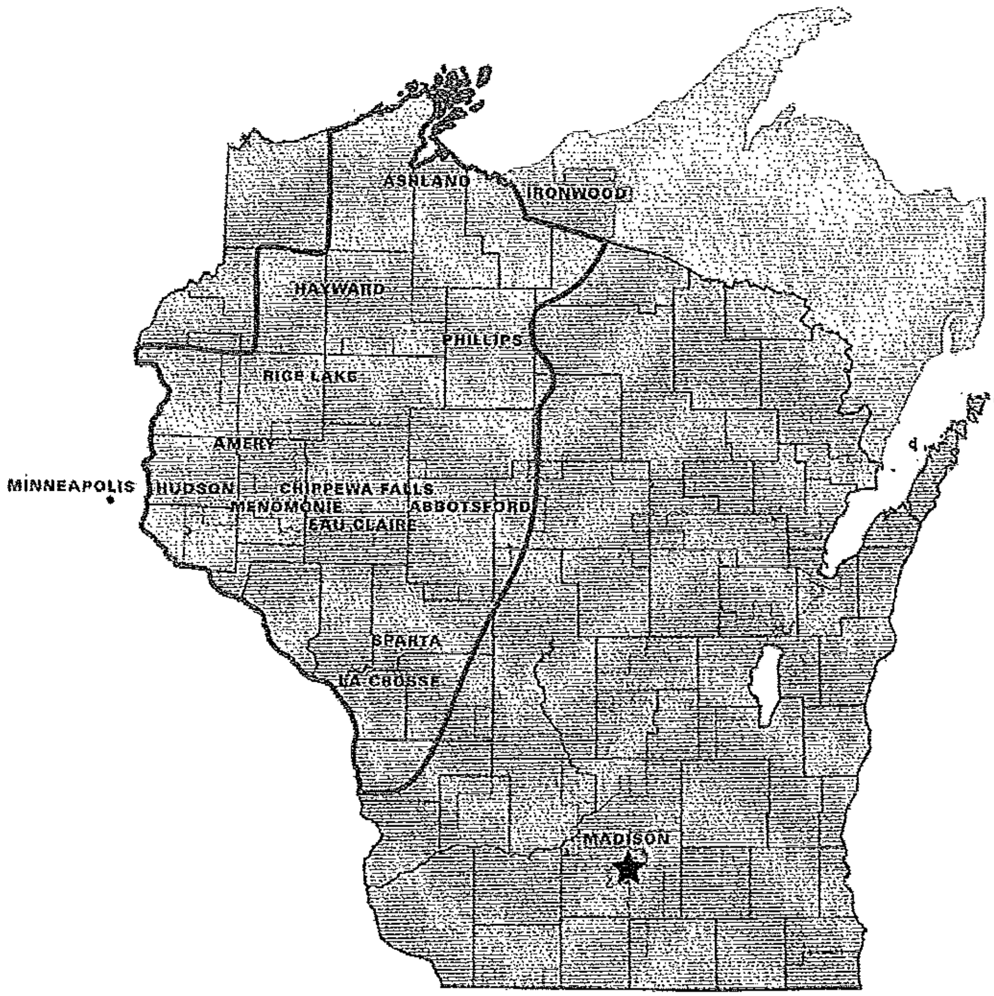
St. Croix County
Hudson, New Richmond, North Hudson, Richmond, Stanton, Star Prairie, Troy

Taylor County
Rib Lake, Westboro

MICHIGAN NATURAL GAS SERVICE TERRITORY

Gogebic County
Bessemer, Ironwood, Wakefield

Ontonagon County
Bergland, McMillan


ASHLAND
IRONWOOD
HAYWARD
PHILLIPS
RICE LAKE
AMERY
MINNEAPOLIS
HUDSON
CHIPPEWA FALLS
MENOMONIE
ABBOTSFORD
EAU CLAIRE
SPARTA
LA CROSSE
MADISON

Name of Respondent Northern States Power Company (Wisconsin)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2009/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	CHIPPEWA AND FLAMBEAU	CHIPPEWA RESERVOIR LOCATED			
2	IMPROVEMENT COMPANY	ON CHIPPEWA RIVER NEAR			
3		WINTER, WI.			
4					
5		EXEMPT LICENSED	11/26/1921		2,832,049
6		PROJECT NO. 8286			
7					
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36					
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38					
39					
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41					
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43					
44					
45					
46					
47	TOTAL				2,832,049

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			732,844	1,161	734,005
2	Steam Production Plant	3,050,091				3,050,091
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	6,538,122		176,369	-44,139	6,670,352
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	1,393,508				1,393,508
7	Transmission Plant	12,153,797			-127	12,153,670
8	Distribution Plant	20,598,669	204		151,339	20,750,212
9	Regional Transmission and Market Operation					
10	General Plant	1,354,533			7,480	1,362,013
11	Common Plant-Electric	3,221,215		3,164,246	113,423	6,498,884
12	TOTAL	48,309,935	204	4,073,459	229,137	52,612,735

B. Basis for Amortization Charges

Account 404
Column (d) Franchises for Hydraulic Production Plant - Conventional is amortized over the license life of the plant and Intangible Plant and Common Plant - Electric (Software) are amortized over their expected useful lives of 3, 5, or 7 years.

Account 405
Column (e) Excess AFUDC is amortized over the average life of the property.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	311	13,802					13.60
13	312	72,028					13.70
14	314	9,014					12.90
15	315	6,677					13.00
16	316	1,300					12.60
17	SUBTOTAL STEAM	102,821					
18							
19	331	18,529					23.00
20	332	128,309					23.20
21	333	56,354					23.30
22	334	27,458					22.70
23	335	4,867					22.80
24	SUBTOTAL HYDRO	235,517					
25							
26	341	2,453					7.70
27	342	3,261					8.40
28	343	33,362					8.50
29	344	20,154					6.80
30	345	6,815					6.50
31	346	1,482					4.40
32	SUBTOTAL PEAKING	67,527					
33							
34	352	9,269					
35	353	135,231					
36	354	2,988					
37	355	142,491					
38	356	98,177					
39	357	66					
40	358	229					
41	359	26					
42	SUBTOTAL TRANS	388,477					
43							
44	361	4,435					
45	362	95,313					
46	364	87,547					
47	365	96,946					
48	366	14,303					
49	367	76,661					
50	368	90,226					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	369	79,791					
13	370	26,139					
14	371	5,105					
15	373	7,869					
16	SUBTOTAL DIST	584,335					
17							
18	302	4,393					26.00
19	303	4,261					
20	390	7,621					
21	391	3,070					
22	391.1	225					
23	392*						
24	392*						
25	393	137					
26	394	8,124					
27	395	2,889					
28	396*						
29	397	10,892					
30	398	18					
31	SUBTOTAL GENERAL	41,630					
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47	GRAND TOTAL	1,420,307					
48							
49							
50	* See Footnote						

Schedule Page: 336.1 Line No.: 21 Column: a

391 Office Furniture and Equipment

Schedule Page: 336.1 Line No.: 22 Column: a

391.1 Information System Computers

Schedule Page: 336.1 Line No.: 50 Column: a

392/396 Separate Provision is charged to clearing accounts monthly, depreciation expense and depreciable plant balances are shown below.

		Charged To Clearing Accts	Depreciable Plant Base
392	General Transportation Equipment	1,139,578	11,872,165
396	Power Operated Equipment	257,854	3,520,711
	Total	1,397,432	15,392,876

Footnotes: Section C

(1) Column (b) Computation
Depreciable Plant Balances are an average of the beginning and ending plant balances for the year.

(2) Column (c) through (g)
Subaccounts 311-346: A remaining life technique is applied to each generating facility. Therefore, column (g) represents dollar weighted composites at the plant subaccount level and column (c), (e), and (f) do not apply.

An Annual Review of Remaining Lives 2007, Docket No. 4220-DU-106 was filed with the PSCW in May 2007.

The Remaining Life changes were effective Jan. 1, 2007, and remain in effect through Dec. 31, 2010.

The approved Remaining Lives allow for the "passage of time adjustment" until there is a change in Remaining Life.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

SEE INSERT PAGES 356.1 AND 356.2 FOR COMMON UTILITY PLANT AND ACCUMULATED PROVISIONS.

Common Utility Plant classification was included in original cost and reclassification studies filed with the Federal Power Commission on March 30, 1940.

GENERAL BASIS USED IN ALLOCATING TO UTILITY DEPARTMENTS, COMMON UTILITY PLANT AND DEPRECIATION.

COMMON UTILITY PLANT AND DEPRECIATION
Plant and Depreciation provisions are allocated on the basis of average percentages of utility plant in service, gross revenue and operating expenses (exclusive of joint utility administrative and general expenses, depreciation and taxes) of each department to the total. (Electric 89.01% and Gas 10.99%)

Schedule Page: 356.1
Line No.: n/a
Column: n/a

Common Utility Plant and Accumulated Provision for Depreciation. The Form 1 reports common utility plant and accumulated provision for depreciation allocated to the electric department at the end of the year. The Utility uses a 13-month average calculation for the electric department common utility plant and accumulated provision for depreciation in the formula.

COMMON UTILITY PLANT IN SERVICE

		Allocated to Utility Departments	
Account (a)	Cost at Dec 31, 2009 (b)	Electric (c)	Gas (d)
301 Organization	0	0	0
303 Misc. Intangible Plant	32,038,983	28,517,899	3,521,084
389 Land and Land Rights	2,200,441	1,958,613	241,828
390 Structures and Improvements	34,590,171	30,788,711	3,801,460

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

391 Office Furniture & Equipment	11,885,460	10,579,248	1,306,212
392 Transportation Equipment	2,998,116	2,668,623	329,493
393 Stores Equipment	807,890	719,103	88,787
394 Tools, Shop & Garage Equipment	1,542,432	1,372,919	169,513
395 Laboratory Equipment	31,019	27,610	3,409
396 Power Operated Equipment	279,876	249,118	30,758
397 Communication Equipment	14,033,364	12,491,097	1,542,267
398 Miscellaneous Equipment	72,105	64,181	7,924
Total	100,479,857	89,437,122	11,042,735
COMMON UTILITY PLANT HELD FOR FUTURE USE			
389 Land and Land Rights	0	0	0
COMMON UTILITY CONSTRUCTION WORK IN PROGRESS			
General Plant	6,700,701	5,964,294	736,407

ACCUMULATED PROVISION FOR DEPRECIATION

Item (a)	Common Utility Plant in Service (b)
Balance Beginning of Year	56,840,458
Depreciation accruals for year charged to:	
Common Utility plant expense - General (Acct 403)	3,589,420
Common Utility plant expense - Misc Intangible Plant (Acct 404)	3,580,874
Transportation expense - clearing	313,527
Total Depreciation accruals	7,483,821
Net charges for plant retired	
Book cost of plant retired	(7,661,542)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Wisconsin)	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Cost of Removal	(50,136)
Salvage (credit)	-
Net charges for plant retired	(7,711,678)
Transfers	-
Balance end of year	56,612,601

COMMON UTILITY ACCUMULATED PROVISION FOR DEPRECIATION
ALLOCATION TO UTILITY DEPARTMENTS

	Electric	Gas	Total
General Plant	50,390,877	6,221,724	56,612,601

"Non-Legal" ARO Balances

	Electric	Gas	Total
General Plant	(171,117)	(21,128)	(192,245)

COMMON UTILITY EXPENSES

	Common Cost at Dec. 31, 2009	Allocated to Utility Departments: Electric	Gas
403 Depreciation Expense	3,589,420	3,221,215	368,205

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
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3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

404	Amortization of Software	3,580,874	3,164,246	416,628
408.1	Taxes Other Than income Taxes	1,286,789	1,087,737	199,052
409.1	Income Tax	29,377,407	26,414,266	2,963,141
901	Supervision	55,223	40,359	14,864
902	Meter Reading Expense	4,363,761	3,189,492	1,174,269
903	Customer Records & Collections	5,708,755	4,172,651	1,536,104
904	Uncollectable Accounts	131,529	96,159	35,370
905	Misc. Customer Assistance Expense	12,383	9,052	3,331
908	Customer Assistance Expense	1,859,781	1,429,295	430,486
909	Informational & Instructional Expense	273,208	209,894	63,314
912	Demonstration & Selling	264,888	189,346	75,542
920	Administrative & General Salaries	9,272,034	8,257,165	1,014,869
921	Office Supplies & Expense	7,386,809	6,578,283	808,526
922	Administrative Expenses Transfered	(2,318,616)	(2,064,720)	(253,896)
923	Outside Services	1,207,941	1,075,646	132,295
924	Property Insurance	1,263,943	1,125,558	138,385
925	Injury & Damages	1,176,496	989,185	187,311
926	Employee Pensions & Benefits	3,033,706	2,550,701	483,005
928	Regulatory Commission	283,896	252,780	31,116
929	Duplicate Charge Credit	(10,242)	(9,122)	(1,120)
930.1	General Advertising	534,415	475,922	58,493
930.2	Miscellaneous General	297,313	264,798	32,515
931	Rents	2,694,141	2,399,229	294,912
935	Maintenance of General Plant	84,043	74,844	9,199
		-----------	----------	---------
Total		75,409,897	65,193,982	10,215,915

Basis of Allocations of Common Utility Expenses

Account 403,404	3 factor (operating revenue, utility plant in service, supervised o&m)
Account 408.1	3 factor (oper. revenue, utility plant in service, supervised o&m), payroll portion-labor
Account 409.1	pre-tax operating income
Account 901-905	weighted meters billed
Account 906-910	average customer counts
Account 911-917	direct assigned sales expense
Account 925-926	operating labor
Account 920-935	3 factor (oper. revenue, utility plant in service, supervised o&m), all except 925-926

Transactions with Affiliates Annual Reporting

Regulated Operating Companies

	Amounts Billed to Affiliates	Amounts Billed from Affiliates	Other	Net Intercompany (Payable) Receivable
Northern States Power Company (Minnesota)				
Interchange Agreement	109,251,587	389,022,869	0	(279,771,282)
Emission Allowances	0	(11,615)	0	11,615
Interest on Intercompany Notes Payable	0	5,628	0	(5,628)
Credit Line Fees	0	60,833	0	(60,833)
Gas Coordinating Agreement	0	308,932	0	(308,932)
REC Administration Fees	0	68,438	0	(68,438)
Credit Facility Fees	0	33,086	0	(33,086)
Asset Transfers	131,107	809,750	0	(678,643)
Service Billing	476,472	9,235,754	0	(8,759,282)
Customer Receipts/Account Transfers			17,613,248	17,613,248
Remaining (1)	0	0	(24,725,088)	(24,725,088)
	109,859,166	399,533,675	(7,111,840)	(296,786,349)
Public Service Company of Colorado				
Service Billing	62,318	21,894	0	40,424
Customer Receipts/Account Transfers			(499,251)	(499,251)
Remaining (1)	0	0	(80,374)	(80,374)
	62,318	21,894	(579,625)	(539,201)
Southwestern Public Service Company				
Service Billing	3,324	(22,383)	0	25,707
Customer Receipts/Account Transfers			(232,334)	(232,334)
Remaining (1)	0	0	59,391	59,391
	3,324	(22,383)	(172,943)	(147,236)
	109,924,808	**399,533,186**	**(7,864,408)**	**(297,472,786)**

This report is prepared in accordance with Docket 4220-AU-127. Additional information is available upon request.
Black Mountain Gas was sold by Xcel Energy Inc. in October 2003. Cheyenne Light Fuel and Power was sold by Xcel Energy Inc. in January 2005.

(1) Amounts Billed to Affiliates - Generally represents Operating and Maintenance or Capital expenses provided by NSP Wisconsin for the benefit of an affiliate.

Amounts Billed from Affiliates - Generally represents Operating and Maintenance or Capital expenses provided by the affiliate for the benefit of NSP Wisconsin.

Other - Generally represents the net convenience payments and inventory transfers made between NSP Wisconsin and affiliates. A debit balance indicates a receivable, meaning that NSP Wisconsin made more convenience payments and inventory transfers for the affiliates than the affiliates made for NSP Wisconsin.

Net Intercompany (Payable) Receivable - Generally represents the net amount due to NSP Wisconsin by the affiliate (a debit balance) or the net amount owed to the affiliate by NSP Wisconsin (a credit balance) for all transactions occurring in the year.

Intercompany Charges from Xcel Energy Services, Inc. to Northern States Power Company (Wisconsin) for Calendar Year 2009 (excluding convenience payments)

Service Function	Allocation Method	Amount
Accounting, Fin Rptg & Taxes		**3,024,542**
	Allocation	1,382,789
	Direct Assigned	1,641,753
Aviation Services		**435,041**
	Allocation	364,041
	Direct Assigned	71,000
Bus Unit Acctg & Budgting-C&FO		**6,941**
	Allocation	107
	Direct Assigned	6,834
Bus Unit Acctg&Budgeting-EM		**371,034**
	Allocation	63,789
	Direct Assigned	307,245
Bus Unit Acctg&Budgeting-ES		**366,812**
	Allocation	1,223
	Direct Assigned	365,589
Bus Unit Acctg-CO Juris Ldr		**0**
	Allocation	0
Claims Services		**118,867**
	Allocation	1,413
	Direct Assigned	117,454
Constr O&M -Trans Mng		**226,094**
	Allocation	139,319
	Direct Assigned	86,776
Constr, O&M-A&G		**87,445**
	Allocation	70,167
	Direct Assigned	17,278
Constr, O&M-Distribution		**1,474,146**
	Allocation	95,850
	Direct Assigned	1,378,296
Constr, O&M-Substation		**23,305**
	Allocation	1,992
	Direct Assigned	21,312
Constr, O&M-Transm Ops		**132,492**
	Allocation	1,201
	Direct Assigned	131,291

Intercompany Charges from Xcel Energy Services, Inc. to Northern States Power Company (Wisconsin) for Calendar Year 2009
(excluding convenience payments)

Service Function	Allocation Method	Amount
Accounting, Fin Rptg & Taxes		**3,024,542**
Constr, O&M-Transmission		**53,128**
	Allocation	2,397
	Direct Assigned	50,731
Corp Strategy & Bus Dev		**221,293**
	Allocation	197,420
	Direct Assigned	23,873
Corporate Communications		**1,029,391**
	Allocation	760,742
	Direct Assigned	268,649
Customer Service		**3,726,833**
	Allocation	2,717,130
	Direct Assigned	1,009,702
Customer Service - Billing		**611,770**
	Allocation	417,996
	Direct Assigned	193,774
EM - Fuel Procurement		**179,257**
	Allocation	2,132
	Direct Assigned	177,125
EM Reg Trdg-Resource Planning		**305,234**
	Allocation	4,031
	Direct Assigned	301,203
EM Regulated Trading & Mktg		**162,777**
	Allocation	52,709
	Direct Assigned	110,068
Energy Delivery Marketing		**15,762**
	Direct Assigned	15,762
Eng/Design-Common		**216,267**
	Allocation	74,410
	Direct Assigned	141,857
Eng/Design-Elec Dist		**318,538**
	Allocation	108,131
	Direct Assigned	210,407
Eng/Design-Elec Trans/Subst		**2,168,801**

Intercompany Charges from Xcel Energy Services, Inc. to Northern States Power Company (Wisconsin) for Calendar Year 2009 (excluding convenience payments)

Service Function	Allocation Method	Amount
Accounting, Fin Rptg & Taxes		**3,024,542**
Eng/Design-Elec Trans/Subst	Allocation	50,044
	Direct Assigned	2,118,757
Eng/Design-Gas Dist		**65,412**
	Allocation	10,849
	Direct Assigned	54,563
ES Bus Res-Hayden		**235,598**
	Allocation	1,289
	Direct Assigned	234,309
ES Business Resources		**529,537**
	Allocation	1,025
	Direct Assigned	528,512
ES Engineering & Environmental		**1,277,405**
	Allocation	3,095
	Direct Assigned	1,274,310
Executive Management Services		**498,906**
	Allocation	335,990
	Direct Assigned	162,917
Facilities & Real Estate		**3,784,728**
	Allocation	179,925
	Direct Assigned	3,604,803
Facilities Admin Services		**(22)**
	Allocation	(7)
	Direct Assigned	(15)
Finance & Treasury		**651,274**
	Allocation	597,549
	Direct Assigned	53,725
Finance And Treasury-Risk		**530,725**
	Allocation	98,311
	Direct Assigned	432,414
Fleet		**164,970**
	Allocation	1
	Direct Assigned	164,969
Government Affairs		**763,364**
	Allocation	282,382

Intercompany Charges from Xcel Energy Services, Inc. to Northern States Power Company (Wisconsin) for Calendar Year 2009 (excluding convenience payments)

Service Function	Allocation Method	Amount
Accounting, Fin Rptg & Taxes		**3,024,542**
Government Affairs	Direct Assigned	480,983
Human Resources-ES		**31,246**
	Direct Assigned	31,246
Human Resources-SS		**2,035,878**
	Allocation	1,762,258
	Direct Assigned	273,620
Information Technology - ET		**11,902,030**
	Allocation	7,983,893
	Direct Assigned	3,918,136
Information Technology-CFO		**258**
	Allocation	(5)
	Direct Assigned	262
Information Technology-DE-C&FO		**2,636,580**
	Allocation	1,097,178
	Direct Assigned	1,539,402
Information Technology-EM		**355,923**
	Allocation	218,539
	Direct Assigned	137,385
Information Technology-ES		**71,751**
	Allocation	69,281
	Direct Assigned	2,470
Information Technology-GC		**0**
	Allocation	0
	Direct Assigned	0
Information Technology-RE-C&FO		**1,512,464**
	Allocation	775,404
	Direct Assigned	737,061
Information Technology-SS		**125,322**
	Allocation	124,867
	Direct Assigned	455
Internal Audit		**240,387**
	Allocation	177,030
	Direct Assigned	63,357

Intercompany Charges from Xcel Energy Services, Inc. to Northern States Power Company (Wisconsin) for Calendar Year 2009 (excluding convenience payments)

Service Function	Allocation Method	Amount
Accounting, Fin Rptg & Taxes		**3,024,542**
Investor Relations		**180,413**
	Allocation	180,413
Legal		**932,765**
	Allocation	495,924
	Direct Assigned	436,841
Marketing & Sales		**1,740,931**
	Allocation	571,495
	Direct Assigned	1,169,436
Payment & Reporting		**80,390**
	Allocation	80,390
Payroll		**67,263**
	Allocation	67,263
Rates & Regulation		**1,625,697**
	Allocation	48,250
	Direct Assigned	1,577,446
Receipts Processing		**94,190**
	Allocation	94,190
Supply Chain - C&FO		**1,026,526**
	Allocation	67,951
	Direct Assigned	958,575
Supply Chain Special Programs		**21,512**
	Allocation	21,512
Supply Chain-ES(910 Alloc)		**18,077**
	Allocation	1
	Direct Assigned	18,075
Grand Total		**48,477,268**

Appendix A

DESCRIPTION OF SERVICES TO BE PROVIDED BY XCEL ENERGY SERVICES INC. AND DETERMINATION OF CHARGES FOR SUCH SERVICES TO THE OPERATING COMPANIES AND OTHER AFFILIATES

Description of Services Provided

A description of the services provided by Xcel Energy Services is detailed below. Identifiable costs will be directly assigned to the Operating Companies and other affiliates. For costs that are for services of a general nature and cannot be directly assigned, the method of allocation is described below for each service provided. If specific conditions are met (as outlined in the Xcel Energy Services Policies and Procedures Manual), an alternative Labor Dollars Ratio may be used to allocate non-labor costs for any service.

a) Executive Management Services*

Description – Represents charges for Xcel executive management and services, including, but not limited to, officers of Xcel.

Methods of Allocation – Executive Management indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Asset Ratio.

b) Investor Relations*

Description – Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.

Methods of Allocation – Investor Relations indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Asset Ratio.

c) Internal Audit*

Description – Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks.

Method of Allocation – Internal Audit indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*d) Legal**

Description - Provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other legal matters.

Method of Allocation – Legal indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*e) Claims Services**

Description - Provides claims services related to casualty, public and company claims.

Method of Allocation - Claims Services costs will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

*f) Corporate Communications**

Description – Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel system. Manages and tracks all contributions made on behalf of the Xcel system.

Method of Allocation – Corporate Communications indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*g) Employee Communications**

Description – Develops and distributes communications to employees.

Method of Allocation – Employee Communications indirect costs will be allocated based on the Employee Ratio.

*h) Corporate Strategy & Business Development**

Description – Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.

Method of Allocation – Corporate Strategy & Business Development indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*i) Government Affairs **

Description - Monitors, reviews and researches government legislation.

Method of Allocation – Government Affairs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*j) Facilities & Real Estate**

Description – Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.

Method of Allocation – Facilities & Real Estate indirect costs will be allocated to the Operating Companies based on the Square Footage Ratio.

*k) Facilities Administrative Services**

Description – Includes but is not limited to the functions of Mail Delivery, Duplicating and Records Management.

Method of Allocation - Facilities Administrative Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio

*l) Supply Chain**

Description – Includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.

Method of Allocation – Supply Chain will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

m) Supply Chain Special Programs*

Description – Develops and implements special programs utilized across the company such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.

Methods of Allocation – Supply Chain Special Programs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

n) Human Resources*

Description – Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.

Methods of Allocation – Human Resources indirect costs will be allocated based on the Employee Ratio.

o) Finance & Treasury*

Description – Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Method of Allocation – Finance & Treasury indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

p) Accounting, Financial Reporting & Taxes*

Description - Maintains the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.

Method of Allocation – Accounting, Financial Reporting & Taxes indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*q) Business Unit Accounting and Budgeting**

Description - Provides financial analysis, budgeting and administrative support for the business units.

Method of Allocation – Business Unit Accounting and Budgeting indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Asset Ratio.

*r) Payment & Reporting**

Description – Processes payments to vendors and prepares statistical reports.

Method of Allocation – Payment & Reporting indirect costs will be allocated to the Operating Companies based on the Invoice Transaction Ratio .

*s) Receipts Processing**

Description – Processes payments received from customers of the Operating Companies and affiliates.

Method of Allocation – Receipts Processing indirect costs will be allocated based on the Customer Bills Ratio.

*t) Payroll**

Description – Processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.

Method of Allocation – Payroll indirect costs will be allocated based on the Employee Ratio.

*u) Rates & Regulation**

Description – Determines the Operating Companies' regulatory strategy, revenue requirements and rates for electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.

Method of Allocation – Rates & Regulation indirect costs will be allocated to the Operating Companies based on the Revenue Ratio or the Labor Dollars Ratio.

v) Energy Supply Engineering and Environmental*

Description – Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental clean up projects.

Method of Allocation – Energy Supply Engineering and Environmental services will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Labor Dollars Ratio.

w) Energy Supply Business Resources*

Description - Provides performance, specialists and analytical services to the Operating Companies' generation facilities.

Method of Allocation – Energy Supply Business Resources indirect costs will be allocated using the MWh Generation Ratio.

x) Energy Markets Regulated Trading & Marketing*

Description - Provides electric trading services to the Operating Companies' electric generation systems including load management, system optimization and resource acquisition.

Method of Allocation – Energy Markets Regulated Trading & Marketing indirect costs will be allocated to the Operating Companies based on the Total MWh Sales Ratio.

y) Energy Markets – Fuel Procurement*

Description – Purchases fuel for Operating Companies electric generation systems (excluding nuclear).

Method of Allocation – Energy Markets Fuel Procurement indirect costs will be allocated based on the MWh Generation Ratio.

z) Energy Delivery Marketing*

Description - Develops new business opportunities and markets the products and services for the Delivery Business Unit.

Method of Allocation – Energy Delivery Marketing will be direct charged.

aa) Energy Delivery Construction, Operations & Maintenance (COM)*

Description – Constructs, maintains and operates electric and gas delivery systems.

Method of Allocation – Energy Delivery COM indirect costs will be allocated based on the Delivery Services Gross Plant Ratio.

bb) Energy Delivery Engineering/Design*

Description – Provides engineering and design services in support of capacity planning, construction, operations and material standards.

Method of Allocation – Energy Delivery Engineering/Design services will be direct charged, and administrative support functions that cannot be direct charged will be allocated based on the Labor Dollars Ratio.

cc) Marketing & Sales*

Description - Provides marketing and sales services for the Operating Companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning and customer service.

Method of Allocation – Marketing & Sales indirect costs will be allocated based on the Revenue Ratio.

dd) Customer Service*

Description – Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections.

Method of Allocation – Customer Service indirect costs will be allocated based on the Customers Ratio.

ee) Business Systems*

Description – Provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration and systems management. In addition, Business Systems acts as a single point of contact for delivery of all technical services to Xcel Energy. They partner with IBM to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace. They work collaboratively with partners and vendors to identify and co-fund opportunities that significantly benefit Xcel Energy's business.

Method of Allocation – Business Systems indirect costs will be allocated using any of the allocation ratios or combination of ratios.

ff) Aviation Services*

Description – Provides aviation and travel services to employees.

Method of Allocation – Aviation Services will be direct charged.

gg) Fleet*

Description – Oversees the Operating Companies' Fleet Services Group.

Method of Allocation – Fleet will be direct charged.

*Corporate Governance activities within this Service Function will be allocated using the average of the Assets Ratio including Xcel Energy Inc.'s per book assets, Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., and Employee Ratio with number of common officers assigned to Xcel Energy Inc.

Allocation Ratios

The following ratios will be utilized as outlined above.

Revenue Ratio - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc. - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the amount of intercompany dividends. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio with number of common officers assigned to Xcel Energy Inc. - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the number of common officers. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Square Footage Ratio - Based on the total square footage as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Invoice Transaction Ratio – Based on the sum of the monthly number of invoice transactions processed for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually or at such time as may be required due to significant changes.

Customer Bills Ratio – Based on the average of the monthly total number of customer bills issued during the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

MWh Generation Ratio - Based on the sum of the monthly electric MWh generated during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total MWh Sales Ratio - Based on the sum of the monthly electric MWh hours sold during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This includes sales to ultimate customers, wholesale customers, and non-requirement sales for resale. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customers Ratio - Based on the average of the monthly total electric customers (and/or gas customers, or residential, business and large commercial and industrial customers where applicable) for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Labor Dollars Ratio - Based on the XES department (performing center) labor dollars charged to Operating companies and other affiliates for the month. The numerator of which is the labor dollars charged to an Operating Company or affiliate company and the denominator of which is for all Operating Companies and affiliate companies charged by the department for the month.

Delivery Services Gross Plant Ratio - Based on transmission and distribution gross plant for the Delivery Business unit, both electric and gas for the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Meters Ratio - Based on the number of meters at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customer Contacts Ratio - Based on the total annual number of customer contacts at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Accounts Payable Transactions Ratio - Based on the total annual number of accounts payable transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Inventory Transactions Ratio - Based on the total annual number of inventory transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Work Management Transactions Ratio - Based on the total annual number of work management transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Purchasing Transactions Ratio - Based on the total annual number of purchasing transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Plant Ratio - Based on total property, plant and equipment at the end of the prior year ending December 31, the numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Phones Ratio - Based on the number of phones at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Radios Ratio - Based on the number of radios at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Computers Ratio - Based on the number of computers at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Software Application's Users Ratio - Based on the number of users of a specific software application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.